KICK CIRCULATION ANALYSIS FOR

EXTENDED-REACH AND HORIZONTAL WELLS

A Thesis

by

MAXIMILIAN M. LONG

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2004

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Hans C. Juvkam-Wold (Chair of Committee)	Jerome J. Schubert (Member)
Malcolm J. Andrews (Member)	Stephen A. Holditch (Head of Department)

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ABSTRACT

Kick Circulation Analysis for Extended-Reach and Horizontal Wells.

(December 2004)

Maximilian M. Long, B.S., LeTourneau University

Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

Well control is of the utmost importance during drilling operations. Numerous well control incidents occur on land and offshore rigs. The consequences of a loss in well control can be devastating. Hydrocarbon reservoirs and facilities may be damaged, costing millions of dollars. Substantial damage to the environment may also result. The greatest risk, however, is the threat to human life.

As technology advances, wells are drilled to greater distances with more complex geometries. This includes multilateral and extended-reach horizontal wells. In wells with inclinations greater than horizontal or horizontal wells with washouts, buoyancy forces may trap kick gas in the wellbore. The trapped gas creates a greater degree of uncertainty regarding well control procedures, which if not handled correctly can result in a greater kick influx or loss of well control.

For this study, a three-phase multiphase flow simulator was used to evaluate the interaction between a gas kick and circulating fluid. An extensive simulation study covering a wide range of variables led to the development of a best-practice kick circulation procedure for multilateral and extended-reach horizontal wells.

The simulation runs showed that for inclinations greater than horizontal, removing the gas influx from the wellbore became increasingly difficult and impractical for some geometries. The higher the inclination, the more pronounced this effect. The study also showed the effect of annular area on influx removal. As annular area increased, higher circulation rates are needed to obtain the needed annular velocity for efficient kick

removal. For water as a circulating fluid, an annular velocity of 3.4 ft/sec is recommended. Fluids with higher effective viscosities provided more efficient kick displacement. For a given geometry, a viscous fluid could remove a gas influx at a lower rate than water. Increased fluid density slightly increases kick removal, but higher effective viscosity was the overriding parameter. Bubble, slug, and stratified flow are all present in the kick-removal process. Bubble and slug flow proved to be the most efficient at displacing the kick.

DEDICATION

This work is dedicated to my father, Louis H. Long, for his love, support, constant encouragement, and sound advice.

ACKNOWLEDGMENTS

Dr. Hans C. Juvkam-Wold, thank you for your excellent instruction in class and advice regarding this project.

Dr. Jerome Schubert, thank you for providing me with this project and for your guidance and friendship along the way.

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Ray Oskarsen, thank you for answering my many questions and sharing your office with me.

I would also like to thank Minerals Management Service and the Offshore Technology Research Center for funding this project, and the support staff at OLGA for providing technical insight and support and for your interest in this work.

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INTRODUCTION

Hydrocarbon production from a wellbore first began in the United States in 1859. Titusville, located in the northwest corner of Pennsylvania, became the home of the first oil boom. Employed by the Seneca Oil Company, E.L. Drake was commissioned with the task of drilling the first oil well. On 27August 1859, at a depth of 69 ft, that well struck oil. The well produced approximately 20 bbl/D.[1]

Technology and experience have rapidly increased since the days of E.L. Drake, allowing greater amounts of hydrocarbons to be reached and produced with greater efficiency. However, drilling still remains the primary and conventional method implemented to bring the hydrocarbons from the ground to earth's surface.

Hydrocarbons are located in the pore volume of clastic or carbonate reservoirs. The pressure of a given reservoir can be dependent upon a myriad of factors, some of which include stress regime, compaction, diagensis, tectonics, and depositional environment. When drilling, this pressure must be controlled to avoid a blowout or influx of formation fluids. Conventionally, the wellbore is filled with a fluid of a given density to obtain a desired bottomhole pressure. This hydrostatic head is used to offset the reservoir or formation pressure.

The process of controlling the formation pressure in a reservoir is called *well control*. The formal definition of well control is the prevention of uncontrolled flow of formation fluids into the wellbore.[2] In that definition, emphasis should be placed on the uncontrolled flow element; wells are often drilled in an underbalanced condition, which allows formation fluids to flow into the wellbore, to obtain increased penetration rate and minimize formation damage.

Well control is of the utmost importance during drilling operations.[3] **Fig. 1** illustrates losses of well control in the Gulf of Mexico and Pacific Coast regions. These offshore

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This thesis follows the style and format of *SPE Drilling and Completion*.

U.S. data, however, account for only a small fraction of well-control incidents. Numerous additional well-control incidents occur on land rigs and in foreign countries. The consequences of a loss in well control can be devastating. Hydrocarbon reservoirs and facilities may be damaged, costing millions of dollars. Substantial damage to the environment may also result. The greatest risk, however, is the threat to human life.

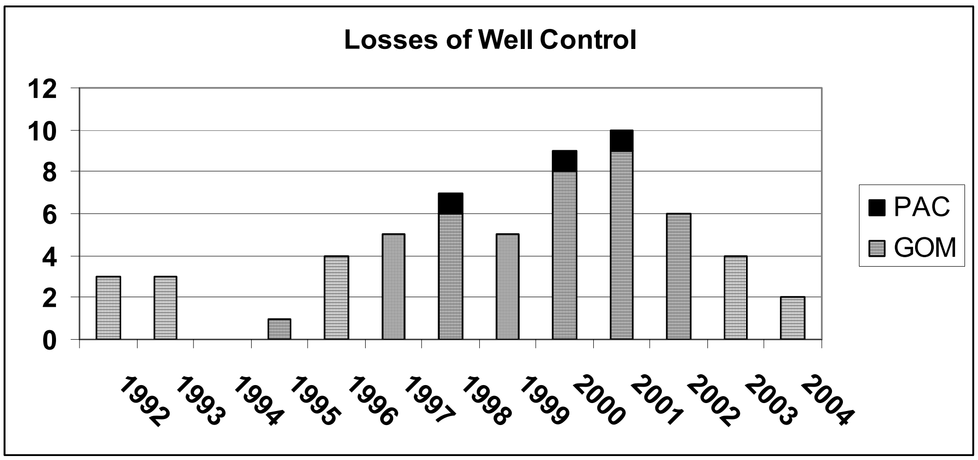

Fig. 1—Losses of well control in the Gulf of Mexico and Pacific Coast.[4]

Well-Control Methods

Unplanned flow of reservoir fluids into the wellbore is commonly called a *kick*. In the event a kick is taken while drilling, drilling operations are suspended and the well is shut in using blowout preventers. Stabilized casing and drillpipe pressures are recorded and used to calculate a new bottomhole pressure and new mud weight to offset the formation's pressure.[3] The kick is then usually circulated from the wellbore using one of two methods: the Wait and Weight method or the Drillers method. Both methods circulate drilling mud down the drillpipe and up the annulus to displace the kick. The bottomhole pressure is kept constant adjusting the choke to hold backpressure at the surface, which prevents an additional influx from entering the wellbore.[3] Upon removal of the kick and placement of the new drilling mud, drilling operations can resume as normal. These methods are conventional well-control procedures. Specialty procedures, such as volumetrics, bull heading, dynamic kills, and relief wells, may also be employed if needed.

Horizontal and Near-Horizontal Well-Control Problems

From the standpoint of well control, it is desirable to transport the kick though the wellbore as one continuous unit. In a vertical or slightly deviated well, buoyancy forces will naturally push the kick fluid upward as a unit. This is not a valid assumption for extended-reach wells, multilateral wells, or horizontal wells, some of which are drilled at inclinations slightly below or above horizontal. **Fig. 2** illustrates a possible well trajectory. In this case, buoyancy forces will cause the kick fluids to remain at the high side of the inclined section. If the correct displacement velocity or flow regime is not present, the buoyancy forces will be the dominant forces and the kick will remain in the wellbore. Washouts (wellbore sections with larger diameter than normal) may also trap gas hydrocarbons and prevent them from being removed by circulation. This is an increasingly important aspect of well control as more horizontal and multilateral wells are drilled with increasingly complex geometries.

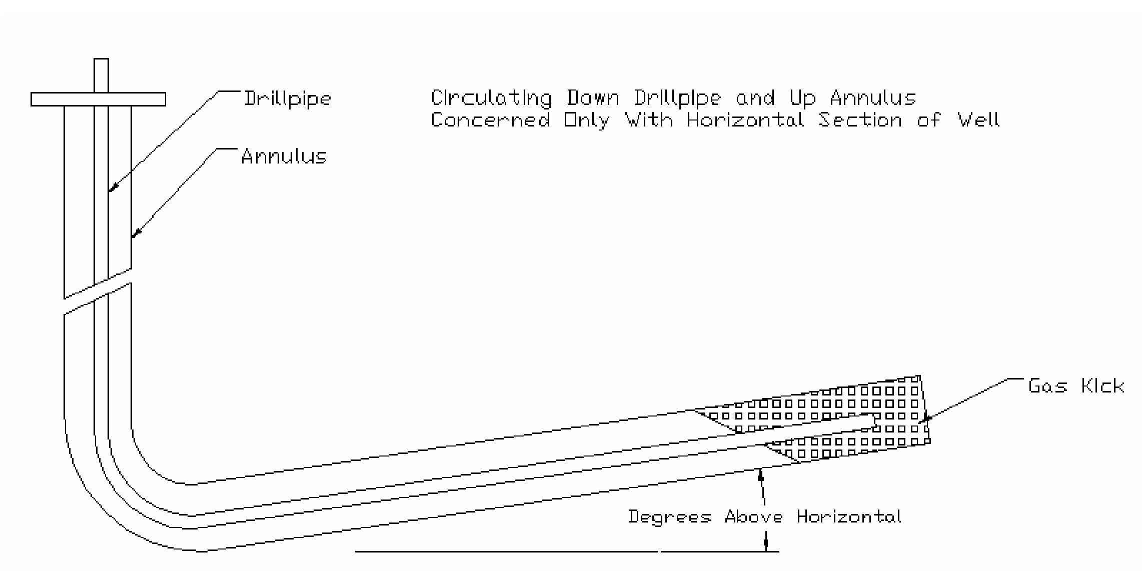

Fig. 2—Horizontal well trajectory may incline upward, trapping kick fluids at toe of wellbore.

LITERATURE REVIEW

Kick Simulators

Although a considerable amount of work has been done in well control, little attention has been given to the issue of kick-removal dynamics. Numerous kick simulators have the capability to model various kick sizes and intensities for any given geometry.[5-11] These simulators are extremely useful in predicting pressure profiles during the kick-removal circulation. The majority of these simulators model the kick circulation as a piston-like displacement process, meaning the kick is displaced by a continually advancing front of drilling mud. This does not allow the drilling and formation fluids to mix appropriately. In reality, a two-phase flow system exists in which the phases flow at differing velocities. This phenomenon is called multiphase flow. Santos[5,6] and Verfting[7,8] have both developed kick simulators capable of modeling the multiphase-flow region. Both simulators use multiphase-flow correlations and complex systems of equations solved numerically.

Physical Experiments

Extensive physical experiments have been conducted using flow loops and test apparatus.[12-17] The majority of this research is aimed at efficiently producing existing wells, alleviating petroleum processing-equipment problems, and gathering and transportation concerns. Baca[16] used a 45-ft test loop to study gas removal in horizontal wellbores with an inclination greater than horizontal. His test setup consisted of outer pipe with an inner diameter of 6.37 in. and inner pipe with an outer diameter of 2.37 in. As gas and liquid were flowed through the test structure at various rates, the flow regime and flow direction of the gas phase, either co-current or concurrent, were recorded. Ustan[17] continued this research with a wider range of gas and liquid rates. These works concluded that a minimum annular superficial liquid velocity for a given gas rate is needed for avoidance of counter-current flow.

Multiphase Flow

Multiphase flow is defined as two or more phases flowing simultaneously through a given area. Flow behavior becomes considerably more complex when two or more phases are present. Differing densities and viscosities lead to phase separation, which facilitates the phase travel at differing velocities in the pipe. The velocities of the different phases determine the flow regime that will occur. **Fig. 3** depicts the various flow regimes for the multiphase horizontal flow.

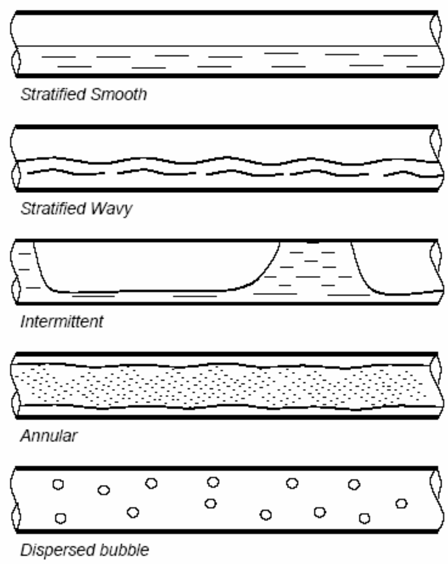

Fig. 3—Horizontal flow may exhibit widely varying patterns.[18]

Flow Patterns

Brill and Mukherjee[19] defined the significant flow patterns used in discussing fluid flow in the wellbore:

Stratified flow is characterized a steady flow of both gas and liquid. The contact area between the two phases can be smooth or wavy.

Slug flow or *intermittent flow* is characterized by a series of slug units. Each unit is composed of a gas pocket called a Taylor bubble, a plug of liquid called a slug, and a film of liquid around the Taylor bubble. The liquid slug, carrying distributed gas bubbles, bridges the pipe and separates two consecutive Taylor bubbles.

Annular flow is characterized by the axial continuity of the gas phase in a central core with the liquids flowing along the walls and as dispersed droplets in the core.

Bubble flow is characterized by a uniformly distributed gas phase and discrete bubbles in a continuous liquid phase. The presence or absence of slippage between the two phases further classifies bubble flow into bubbly and dispersed bubble flows. In bubbly flow, relatively fewer and larger bubbles move faster than the liquid phase because of slippage. In dispersed bubble flow, numerous tiny bubbles are transported by the liquid phase, causing no relative motion between the two phases.

Liquid holdup is defined as the fraction of a pipe cross-sectional area that is occupied by the liquid phase. Empirical correlations can predict liquid holdup for a range of liquid and gas velocities. **Fig. 4** provides a visual of the mechanics of liquid holdup, where HL is the fraction of liquid in the pipe.

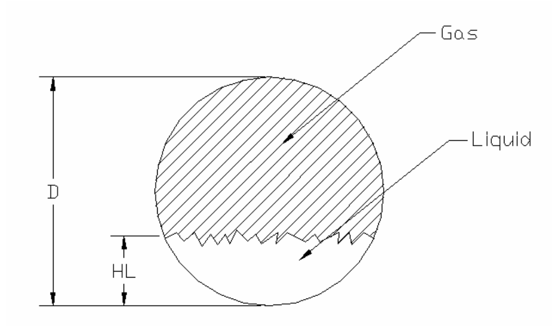

Fig. 4—Liquid holdup diagram.

Superficial velocity is defined by considering a single phase of a multiphase system and assuming it occupies the entire pipe area. The superficial velocity of the liquid phase is defined by dividing the liquid volumetric flow rate by the entire pipe area. The equations for gas and liquid superficial velocities are given below. The previously mentioned flow patterns may also be defined by the superficial velocities for a given geometry. **Fig. 5** illustrates a generic flow pattern map for a given geometry.

$$V_{sg} = \frac{Q_g}{A_t} \qquad\qquad V_{sL} = \frac{Q_L}{A_t}$$

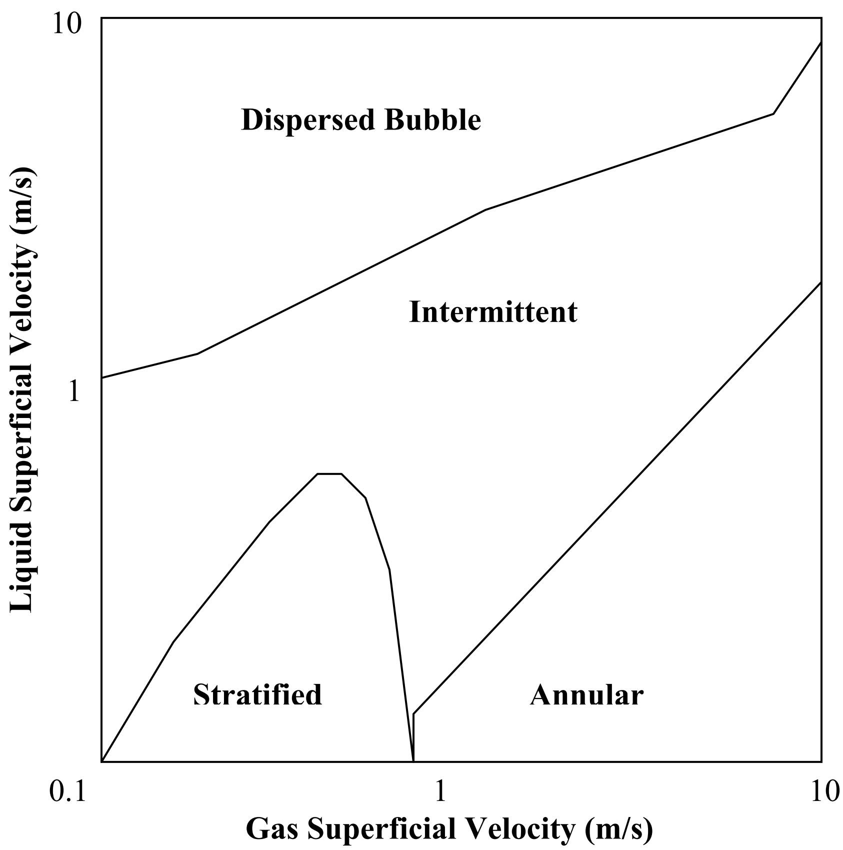

Fig. 5—Generic flow pattern map illustrates effects of superficial velocities.

OBJECTIVES AND PROCEDURES

Research Objectives

The main objective of this work was to accurately model the kick-removal circulation procedure for horizontal wells at varying inclinations above and below true horizontal. The procedures used to reach this objective follow:

- Determine the effects of circulation rate and superficial velocities on kick removal for a given inclination and geometry.
- Determine the flow regimes present during the removal of a kick.
- Determine the effects of wellbore friction on kick removal.
- Generate correlations that model the interaction between annular area and annular velocity.
- Model the effects of mud properties on kick removal
- Provide data that can be used to create a best-practice well-control procedure.

METHODOLOGY OF STUDY

OLGA

OLGA,[15] an industry recognized multiphase computer simulator, was used to model the system. OLGA is capable of modeling a wide range of scenarios by varying fluid properties, pressure, temperature, geometry, trajectory, influx rate, circulation rate, friction, etc. OLGA is based on a one-dimensional, two-fluid model. For the gas and liquid phases, the model consists of separate conservation equations for both mass and momentum. A single energy conservation equation is used for the liquid and gas phase. Solving the system of conservation equations requires averaging and simplification; closure laws are used to replace the information lost in the simplification process. The closure laws describe transfer of heat and momentum between the phases and between the walls of the wellbore and drillpipe. The partial differential equations are solved by using a numerical finite-differencing method. A given number of computational sections is defined along the trajectory of the wellbore, and the solution is advanced in discrete time steps. Multiple runs made by varying input parameters produce a wide spectrum of data. These data compose a data matrix, predicting needed circulation rates for efficient kick removal.

OLGA Input Data

OLGA operates on a system of keyword tabs. Each keyword tab contains information pertaining to a certain aspect of the simulator. For instance, the geometry tab contains information regarding the trajectory of the wellbore, hole size, and friction factor. Once an input file has been generated, multiple cases can be run with varying input values for several parameters.

OLGA Output Data

OLGA is capable of recording a wide range of variables. Liquid holdup, superficial gas and liquid velocities, accumulated liquid and gas at outlet, and flow regime were of primary interest for this study. OLGA outputs data in two forms: trend data and profile data. Trend data are plotted with respect to time for a given location along the wellbore.

Profile data are plotted with respect to distance along the wellbore for a given time. The profile plot also allows time steps through the simulation for monitoring changes in liquid holdup or other parameters.

Test Setup

The trajectory used in the simulation runs has already been illustrated in Fig. 2. The vertical section of the well is 1,500 ft and the horizontal section is 2,500 ft inclined at 10, 5, 0, -5, and -10 degrees. An inclination of zero corresponds to a completely horizontal well. **Table 1** lists horizontal and vertical departures for each inclination. Three commonly used geometries were considered for the simulations. **Table 2** lists hole size, drillpipe size, and effective annular area. The annulus was modeled by a single pipe with a geometrical cross-sectional area equivalent to that of a conventional annulus. As in conventional drilling, water or mud was circulated down the drillpipe and returned up the annulus. A pressure-boundary condition was defined at the outlet of the vertical annular section to maintain a constant pressure at the annular outlet of the horizontal section. For all runs the annular pressure of the horizontal sections at the outlet was kept at 6,000 psi.

Table 1—Horizontal and Vertical Departures

Section Measured Length (ft)		2500
Degrees Above Horizontal	Horizontal Length (ft)	Vertical Height (ft)
10	2,462	434
5	2,490	218
0.0	2,500	0
-5.0	2,490	-218
-10.0	2,462	-434

Table 2—Geometry Data

Geometry	Hole Size (in)	Drill Pipe OD (in)	Weight (lb/ft)	Drill Pipe ID (in)	Annular Area (sq. in)
1	5	3.5	8.5	3.063	10.01
2	7.875	5.0	19.5	4.276	29.07
3	9.875	5.0	19.5	4.276	56.95

Table 3 lists kick-fluid properties used in the simulations. The gas-kick fluid composed of methane, ethane, and propane had a specific gravity of 0.5974. Using a PVT simulator, a table of temperature and pressure was constructed for the dependent gas properties. OLGA uses this table to accurately model gas behavior.

Table 3—Gas Composition

Component	Component	Mole Fraction	Molecular Weigth	yiMi
Nitrogen	N2	0.0000	28.0130	0.0000
Carbon Dioxide	CO2	0.0000	44.0100	0.0000
Hydrogen Sulfide	H2S	0.0000	34.0760	0.0000
Methane	CH4	0.9400	16.0430	15.0804
Ethane	C2H6	0.0300	30.0700	0.9021
Propane	C3H8	0.0300	44.0970	1.3229
Isobutane	i-C4H10	0.0000	58.1240	0.0000
Butane	n-C4H10	0.0000	58.1240	0.0000
Isopentane	i-C5H12	0.0000	72.1510	0.0000
n-Pentane	n-C5H12	0.0000	72.1510	0.0000
n-Hexane	C6H14	0.0000	86.1780	0.0000
Heptane	C7+	0.0000	114.2000	0.0000
		1.0000		17.3054
	Average Molecular Weight			17.3054
	Specific Gravity		γ_g	0.5974

Mud Properties

Water was used as the circulating fluid for the majority of the runs. The remainder of the runs were performed with water-based muds of varying density, plastic viscosity (PV), and yield point (YP). These values were selected from **Fig. 6**[20] and **Table 4,** which depict appropriate plastic viscosity and yield point values for a given mud density. From the PV and YP values, Fanning viscometer numbers were computed and used in calculating the flow-behavior index *n* and the consistency index *K* of the power law. The power law is used to model non-Newtonian fluids and predict their effective viscosity.

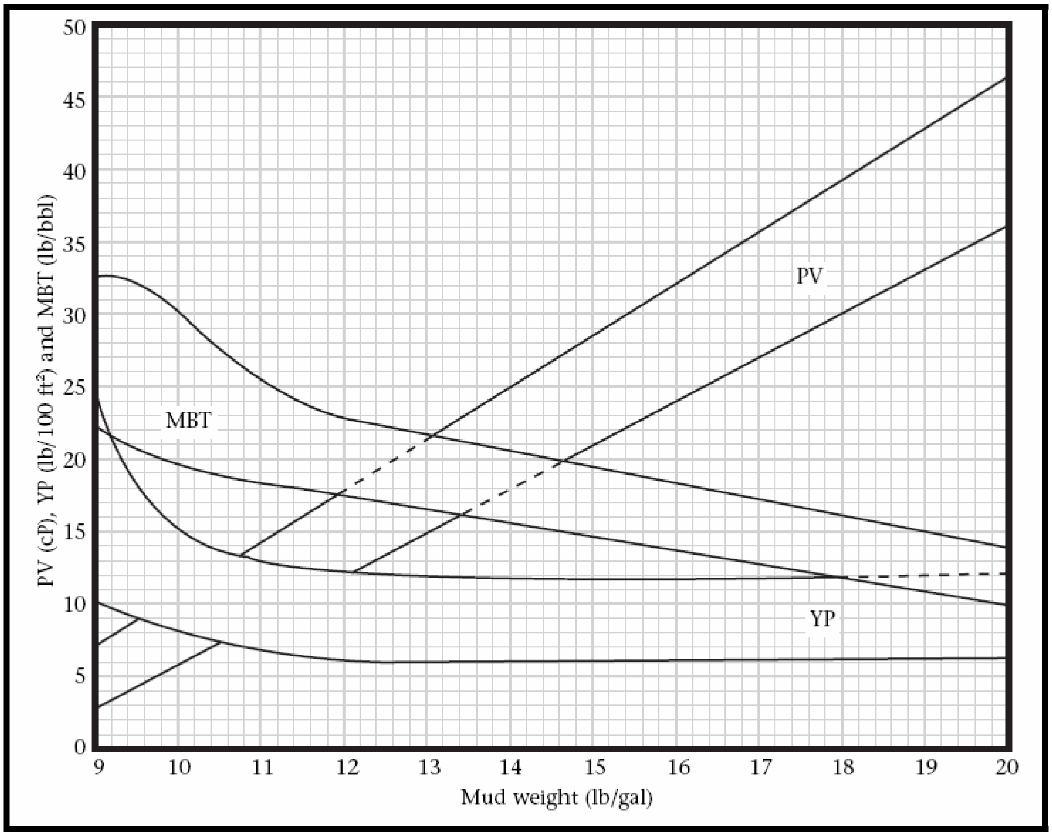

Fig 6—PV and YP for water-based muds.[20]

Table 4—Mud Properties

Density (lb/gal)	PV (cp)	YP (lb/(100 ft^2))	Theta 600	Theta 300	n	K
10	9	12	30	21	0.514	4.344
12	15	9	39	24	0.700	1.559
14	22	9	53	31	0.773	1.275
16	28	9	65	37	0.812	1.192

Simulation Procedure

The simulator may be started as soon as an input file has been entered. For a period of 1,800 seconds the simulator remains idle. This allows the simulator to reach equilibrium from the input data. At 1,801 seconds, gas kick begins to flow into the far end of the horizontal section. The gas kick flows for 300 seconds, accumulating to 15 barrels of net influx. At 3,600 seconds, the circulation procedure begins and does not end until the end of the simulation. This sequence of events was selected to model true-to-life circumstances as closely as possible.

RESULTS

Introduction

The following results were generated from OLGA simulations. Accumulated gas out, liquid holdup, and liquid superficial velocities were measured at the outlet of the annular horizontal section for each of the three geometries at five inclination angles. These figures show the efficiency of kick removal versus time for a specific circulation rate. Similar figures depict the effects of mud properties and wellbore friction. The figures also depict liquid holdup and flow regime versus the length of the horizontal section at a given time.

Runs Performed With Water

Geometry 1

Geometry 1 consists of a 5-in. hole size with 3.5 in. outer-diameter drillpipe. The effective annular area is 10.01 sq. in. **Figs. 7-21** illustrate the results for the five inclinations.

Inclination 10°

Fig. 5 shows the effects of circulation rate on kick removal. The 50-GPM rate is the only circulation rate that does not successfully remove the kick from the horizontal section, as evidenced by the curve lying on top of the x-axis. The 100-GPM rate efficiently transports the kick from the wellbore in approximately 6,800 seconds from the start of the simulation. The simulated kick removal times from the figures can be compared against calculated piston-like displacement times. From **Table 5**, calculated piston-like displacement times may be determined for a given wellbore geometry and circulation rate. A time of 3,600 seconds is added to the calculated piston-like displacement times so the values may be easily compared to the number read directly from the figures. For the 100 gpm for geometry 1, a value of 4,380 seconds is read from Table 5. The difference between the two numbers illustrates the interaction of the gas kick’s buoyancy forces opposing the forces of the circulating fluid. For the 50 gpm case, the drag force of the circulating fluid is not sufficient to overcome the buoyancy of the gas kick. The kick will remain in the hole. The 200- and 300-gpm rates remove the kick in times approximately equal to that of piston-like displacement.

Fig. 7 depicts the liquid holdup at the outlet, but also is an indication which flow regime is present for each rate case. For the 75- and 100-GPM cases, a jagged line is present. This is representative of slug flow. The 200- and 300-GPM cases show a smooth up-and-down increase and decrease of the liquid holdup line. The liquid holdup nearly reaches a value of zero, meaning the annulus would be completely filled with gas. These features correspond to bubble flow. Fig. 8 shows that an annular velocity of 2.4 ft/sec can remove the kick from the wellbore, and an annular velocity of 3.25 ft/sec can do it efficiently.

Table 5—Kick Removal Time for Horizontal Section Assuming Piston-Like Displacement (Adjusted for circulation starting at 3,600 seconds)

Circulation Rate	Well Geometry		
	1	2	3
15	8802	18702	33186
45	5334	8634	13462
60	4900	7376	10997
75	4640	6620	9517
100	4380	5865	8038
125	4224	5412	7150
150	4120	5110	6559
175	4046	4894	6136
200	3990	4733	5819
225	3947	4607	5572
250	3912	4506	5375
275	3884	4424	5214
300	3860	4355	5079
350	3823	4247	4868
400	3795	4166	4709
450	3773	4103	4586
500	3756	4053	4488
550	3742	4012	4407
600	3730	3978	4283
650	3720	3949	4283
700	3711	3924	4234

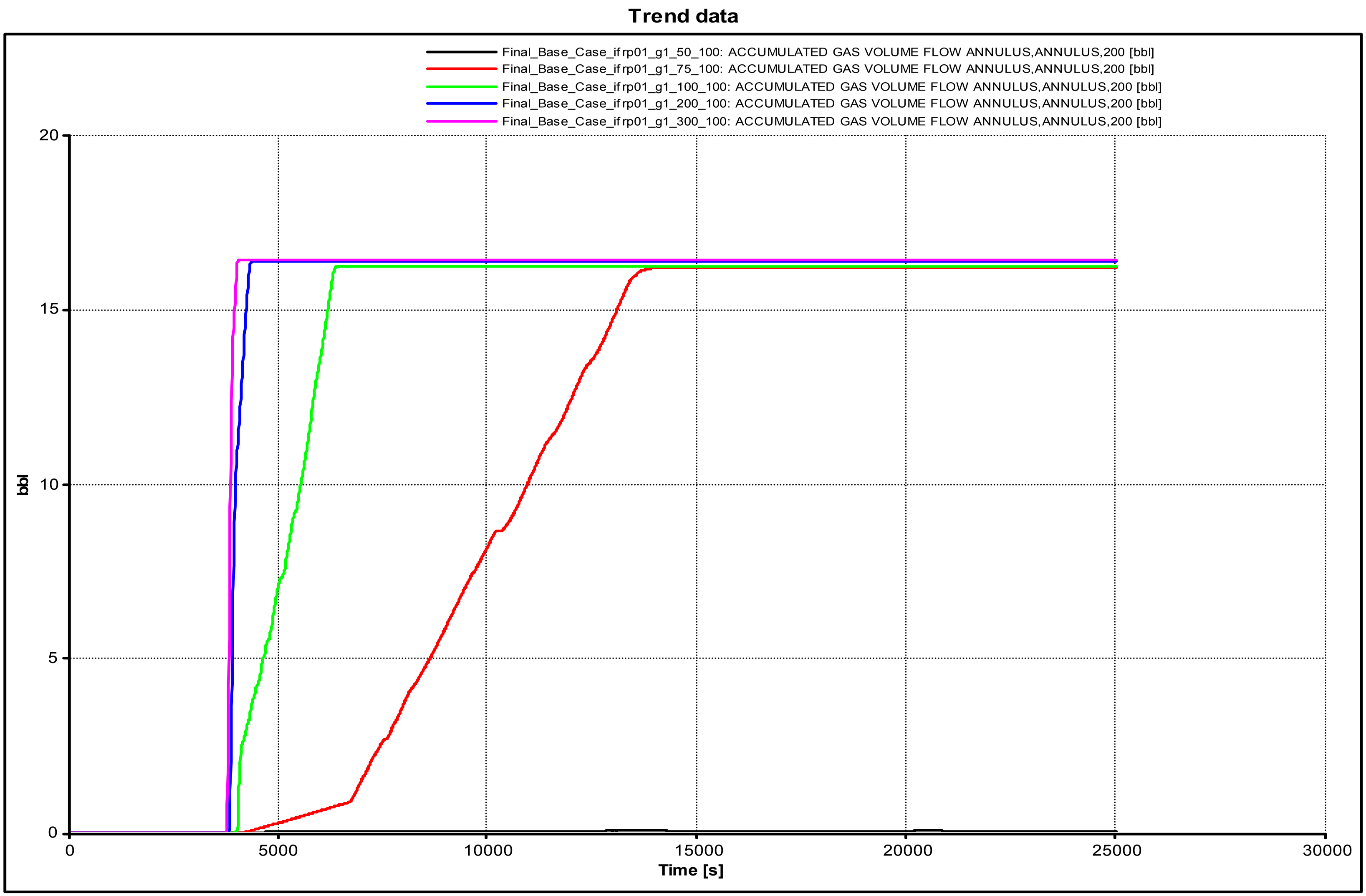

Fig. 7—Accumulated gas out at outlet of annulus, Geometry 1, inclination 10°, circulation rate 50, 75, 100, 200, & 300 GPM.

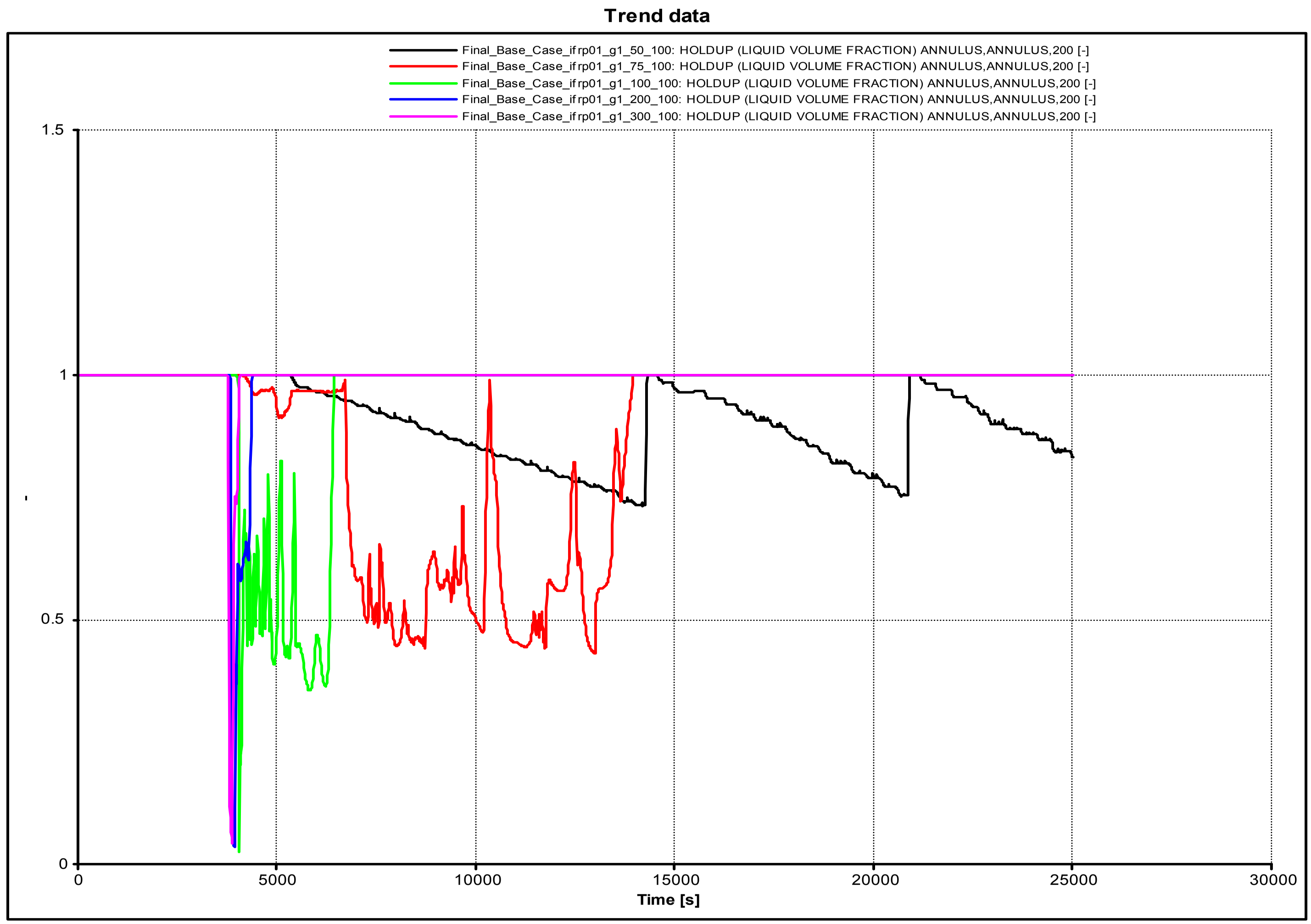

Fig. 8—Liquid holdup at outlet of annulus, Geometry 1, inclination 10°, circulation rate 50, 75, 100, 200, & 300 GPM.

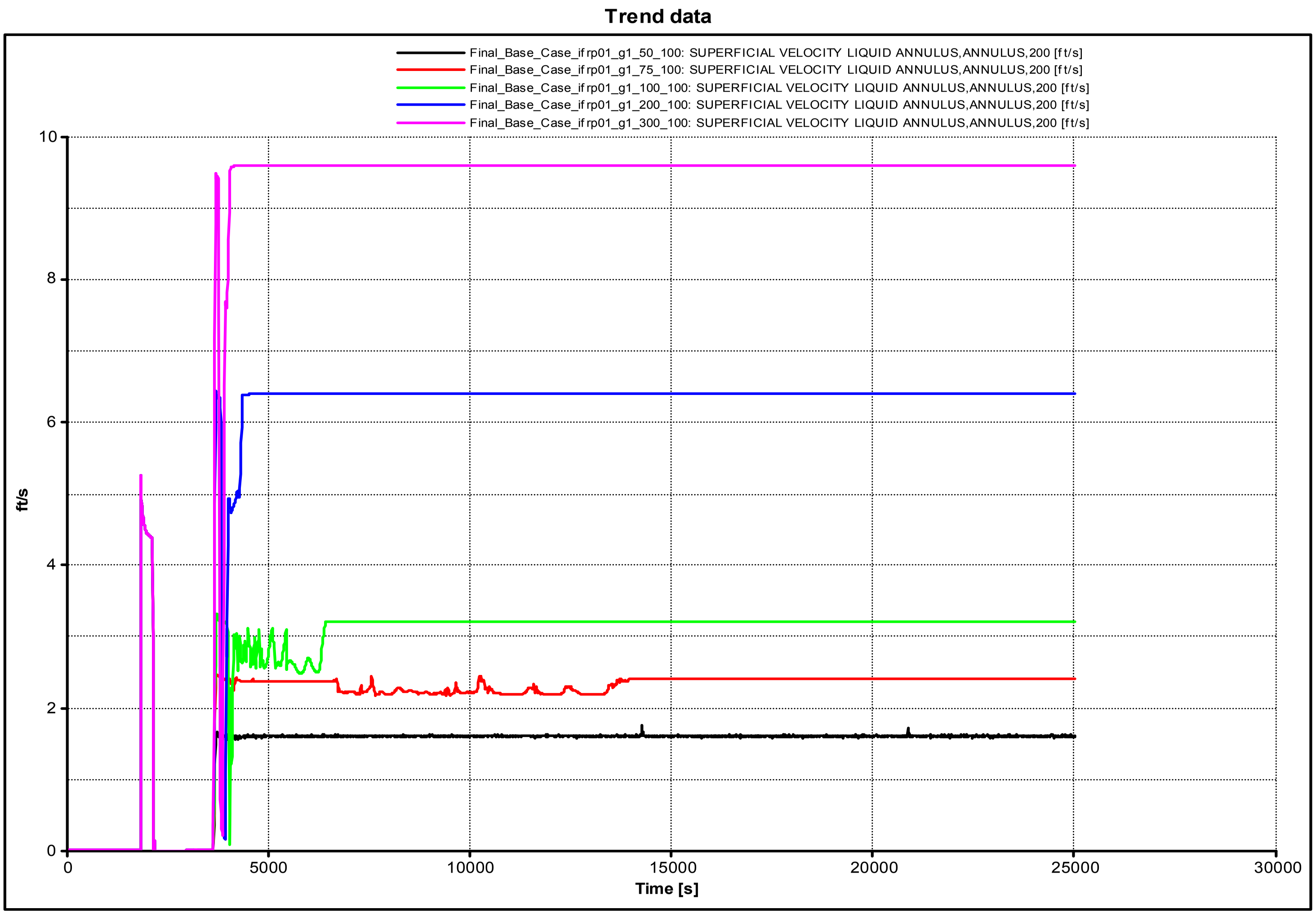

Fig. 9—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 10°, circulation rate 50, 75, 100, 200, & 300 GPM.

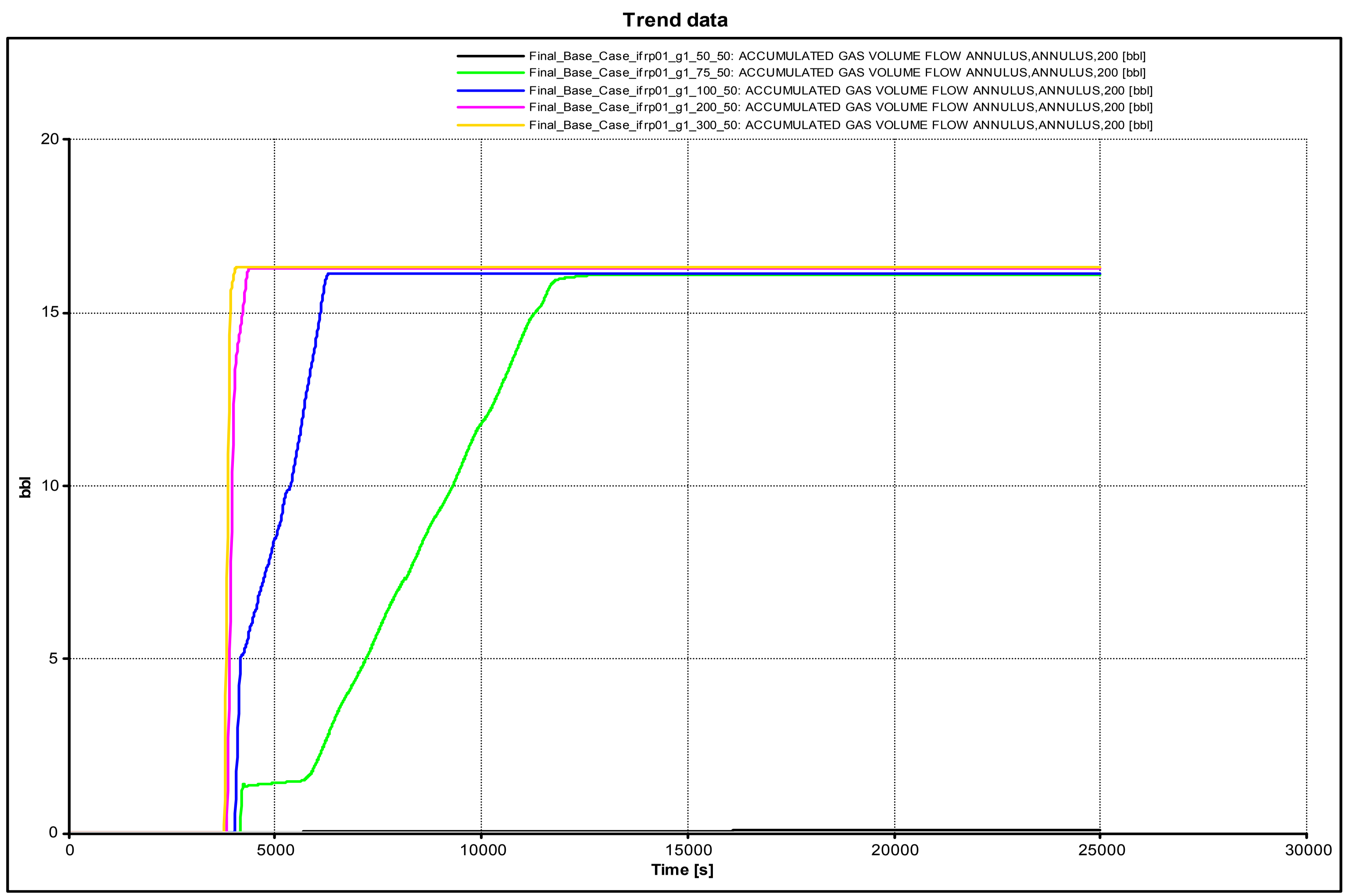

Fig. 10—Accumulated gas out at outlet of annulus, Geometry 1, inclination 5°, circulation rate 50, 75, 100, 200, & 300 GPM.

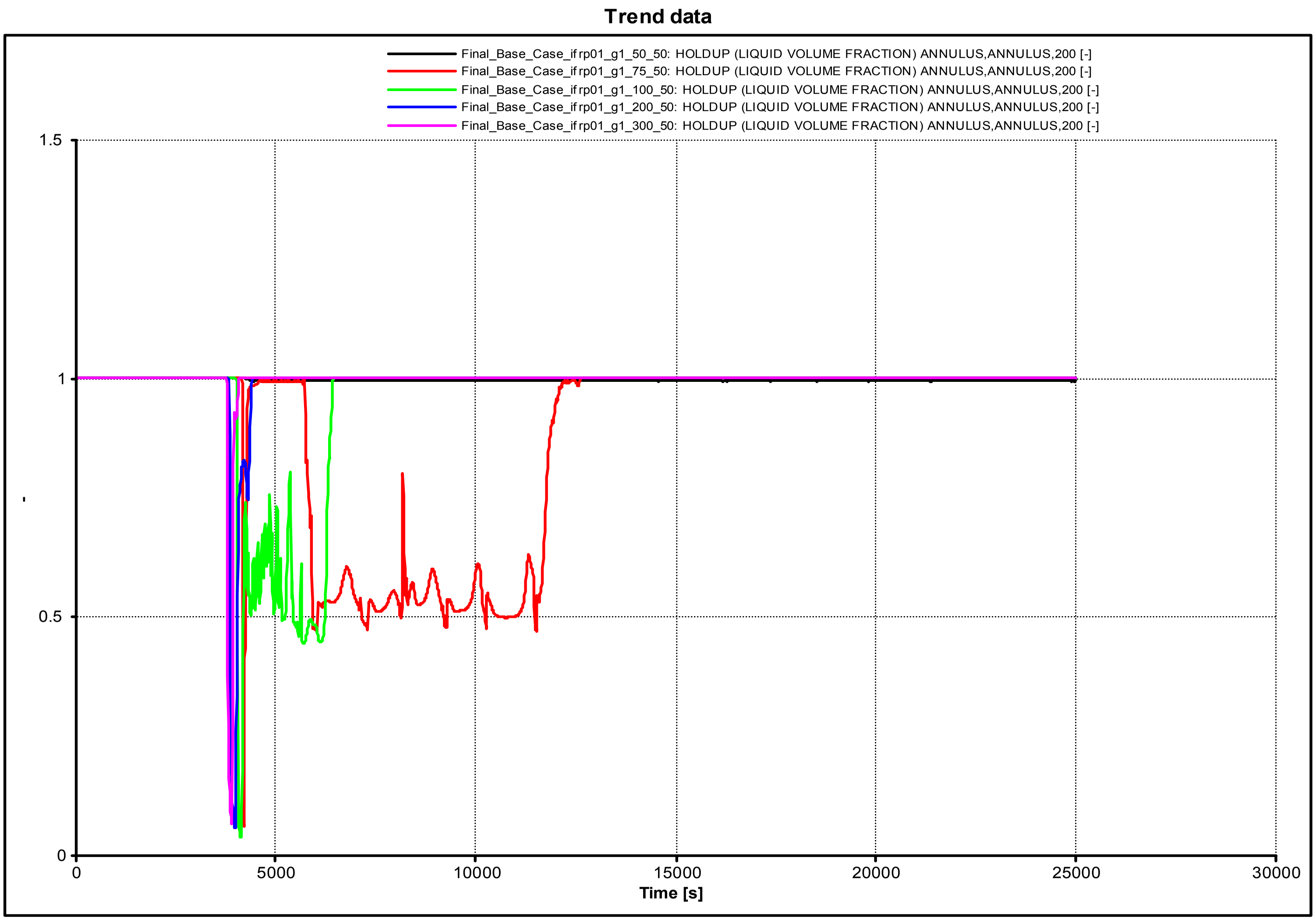

Fig. 11—Liquid holdup at outlet of annulus, Geometry 1, inclination 5°, circulation rate 50, 75, 100, 200, & 300 GPM.

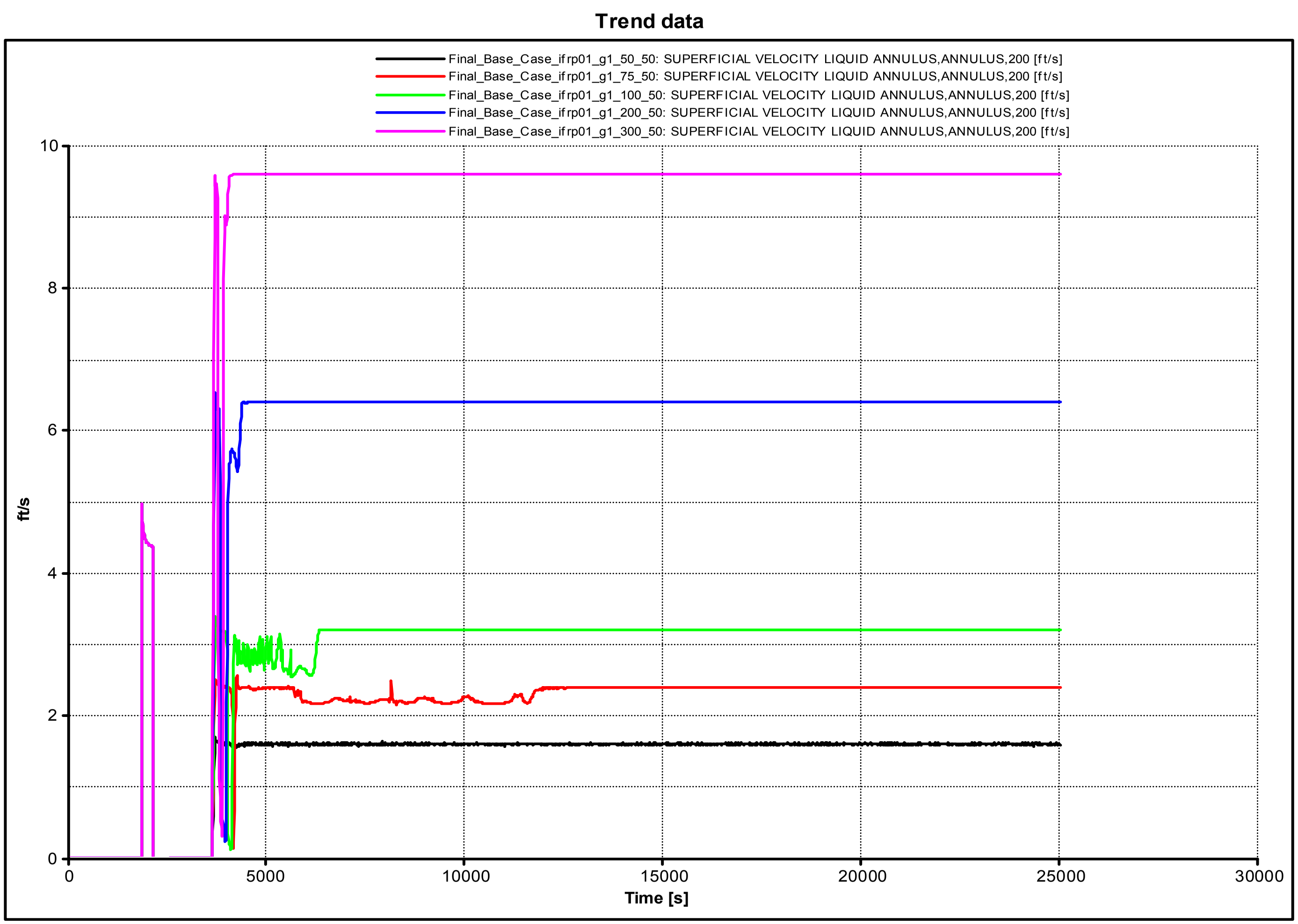

Fig. 12—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 5°, circulation rate 50, 75, 100, 200, & 300 GPM.

Inclination 5°

Figs. 10 to 12 represent the data for an inclination of 5º above horizontal. The same conclusions can be reached for this inclination as were reached for the 10º case. However, the curves in Fig. 10 are shifted to the left when compared to Fig. 7. This reflects a decrease in gas-kick buoyancy forces resulting from the lower inclination angle.

Inclination 0°

For a completely horizontal inclination, the gas kick was efficiently removed at all simulated circulation rates. Fig. 13 shows smooth, similar, and offset curves. The kick removal times are close to a piston-like displacement model for all circulation rates. Fig. 14 shows smoothly increasing and decreasing liquid holdup curves. This is consistent with a stratified flow regime. It is important to note that this model assumes a completely smooth annulus with no undulations or washouts.

Inclination -5°

For an inclination of 5º below horizontal, the gas begins migrating up the annulus instantaneously. When circulation begins at 3,600 seconds, the majority of the gas kick has left the horizontal section. During the gas-kick influx, a small amount of gas begins to migrate up the drillpipe instead of the annulus. Once circulation begins, the gas is displaced from the drillpipe into the annulus and removed from the annular horizontal section. This phenomenon is depicted in Fig. 16 by the irregular top portion of each curve. The shape or slope of the top portion of these curves is dependent on the circulation rate. The effect of the gas in the drillpipe may also be seen in Fig. 17 and Fig. 18.

Inclination -10°

For an inclination of 10º below horizontal, the results were similar to the results of the case with an inclination of 5º below horizontal. However, the steeper slope of the horizontal section causes the curves in Fig. 19 to shift slightly to the left in comparison to Fig. 16. Fig. 20 is similar to Fig. 18 and is therefore of little interest.

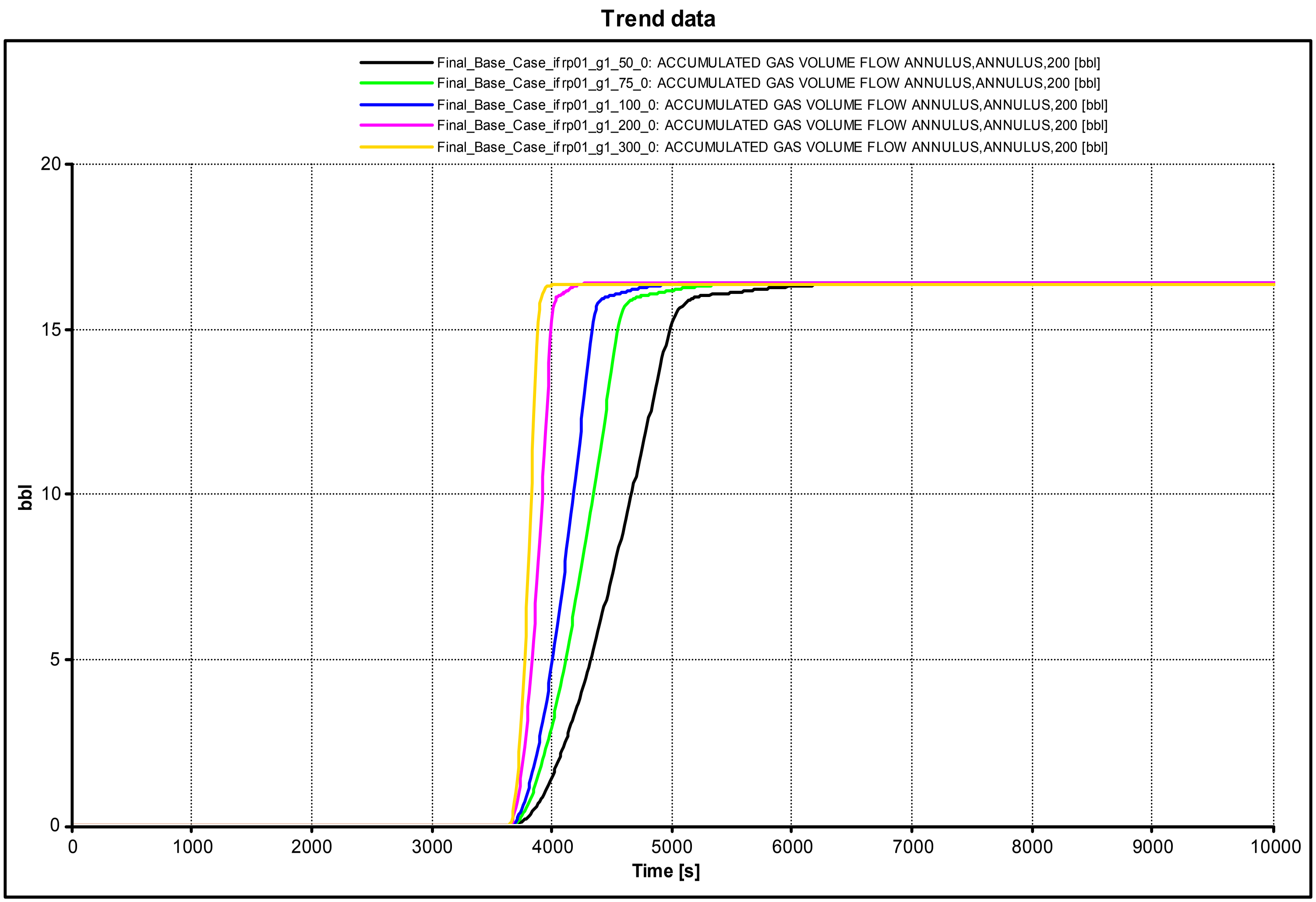

Fig. 13—Accumulated Gas out at outlet of annulus, Geometry 1, inclination 0°, circulation rate 50, 75, 100, 200, & 300 GPM.

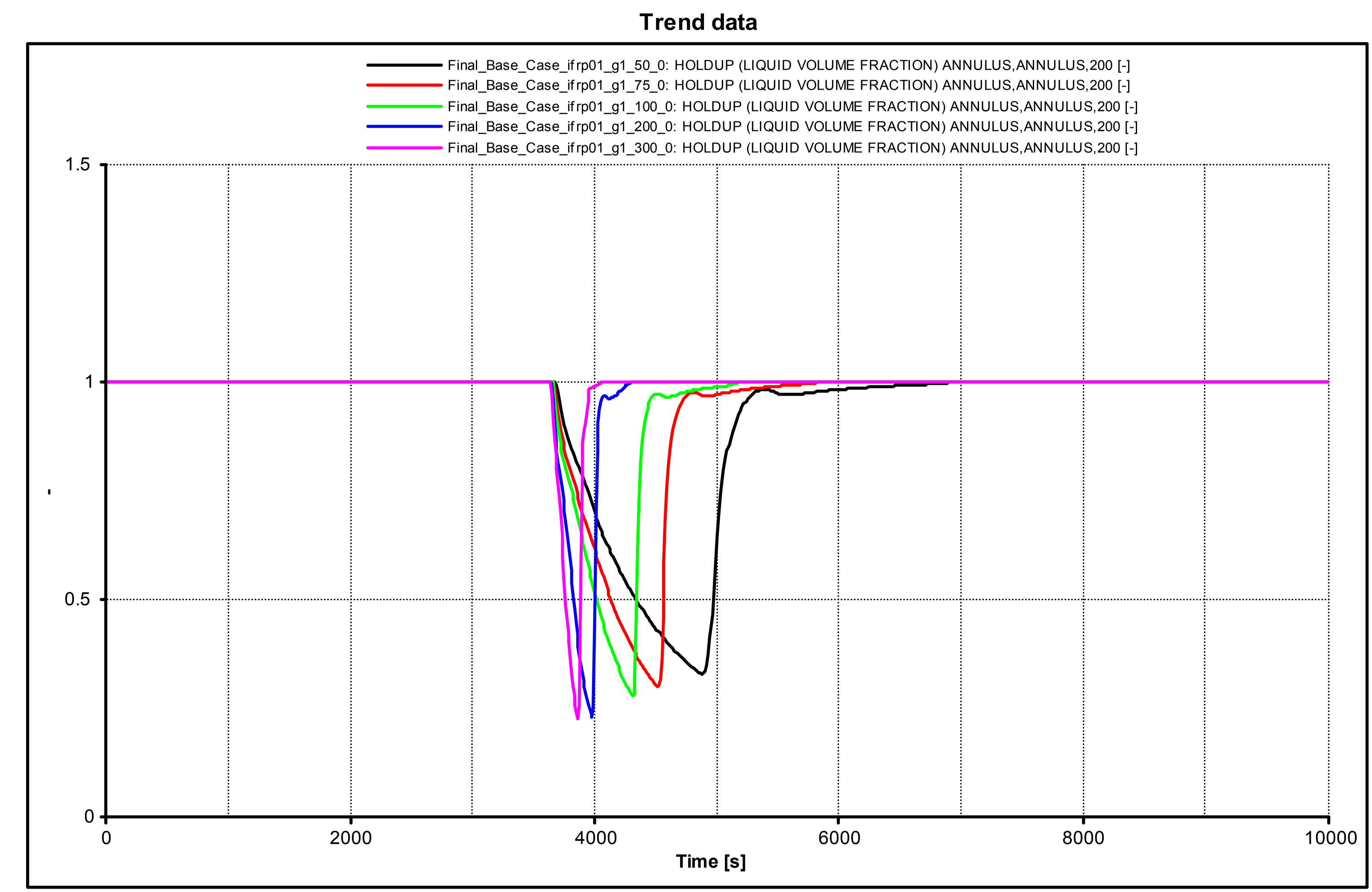

Fig. 14—Liquid holdup at outlet of annulus, Geometry 1, inclination 0°, circulation rate 50, 75, 100, 200, & 300 GPM.

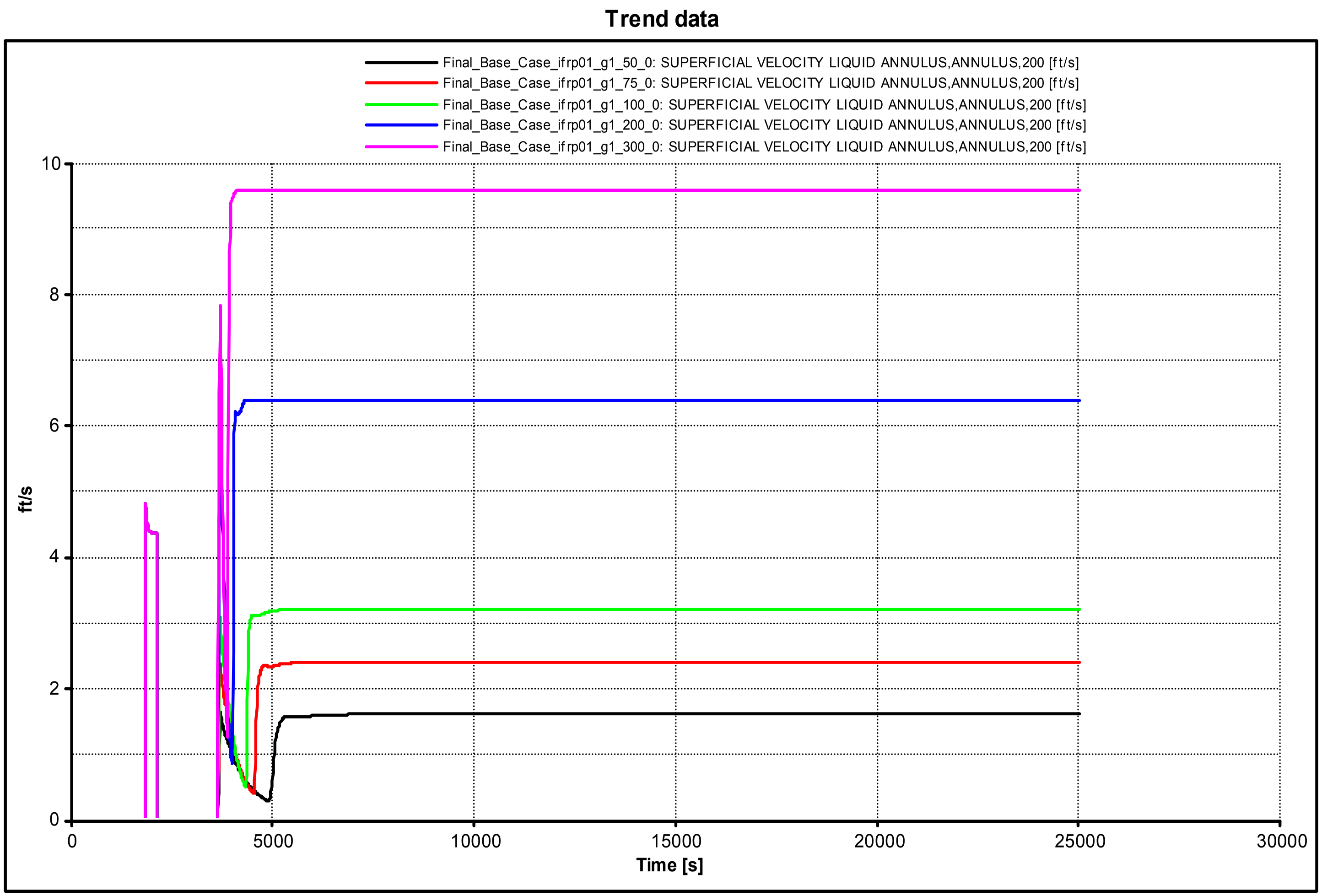

Fig. 15—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 0°, circulation rate 50, 75, 100, 200, & 300 GPM.

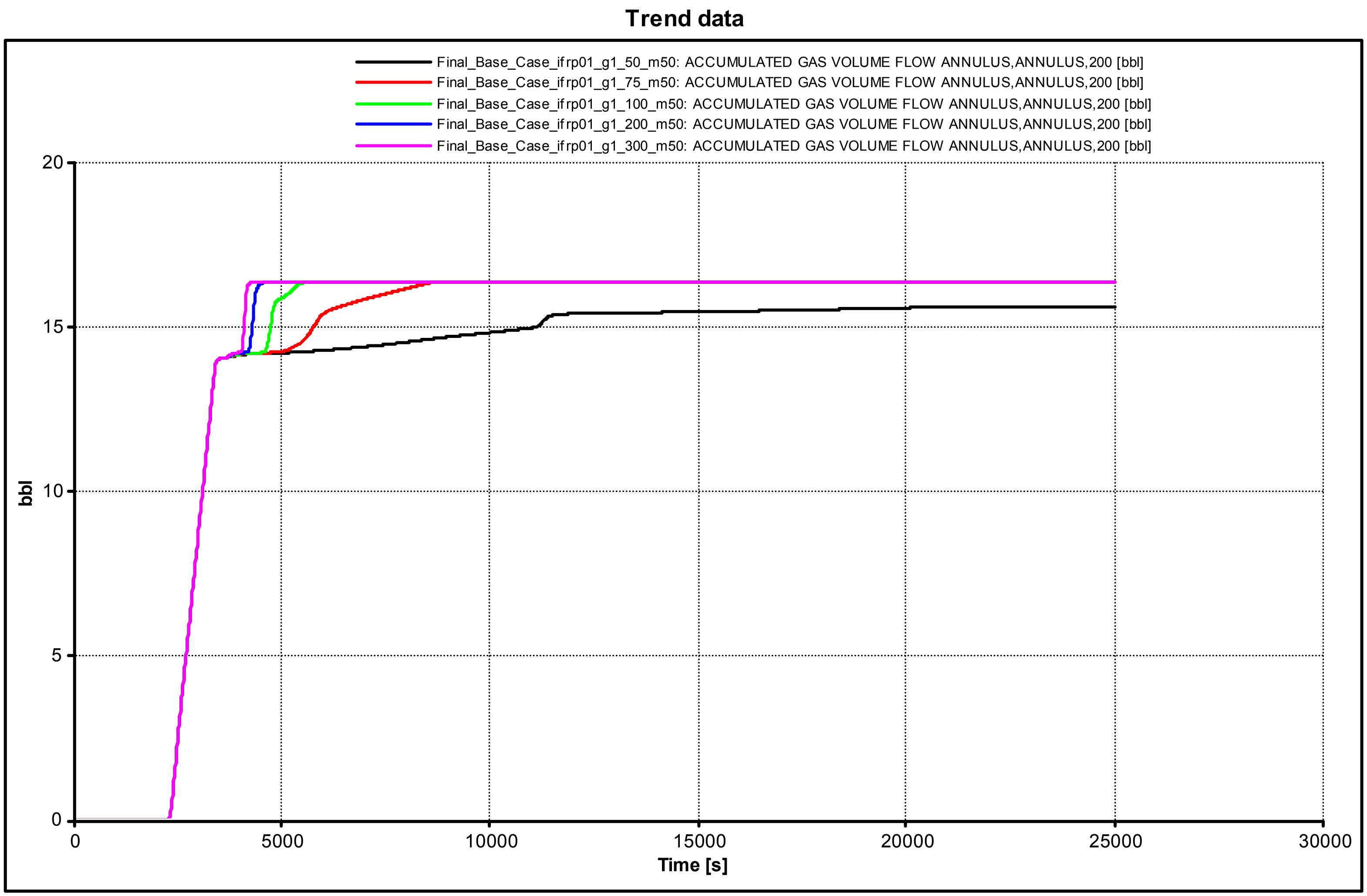

Fig. 16—Accumulated gas out at outlet of annulus, Geometry 1, inclination -5°, circulation rate 50, 75, 100, 200, & 300 GPM.

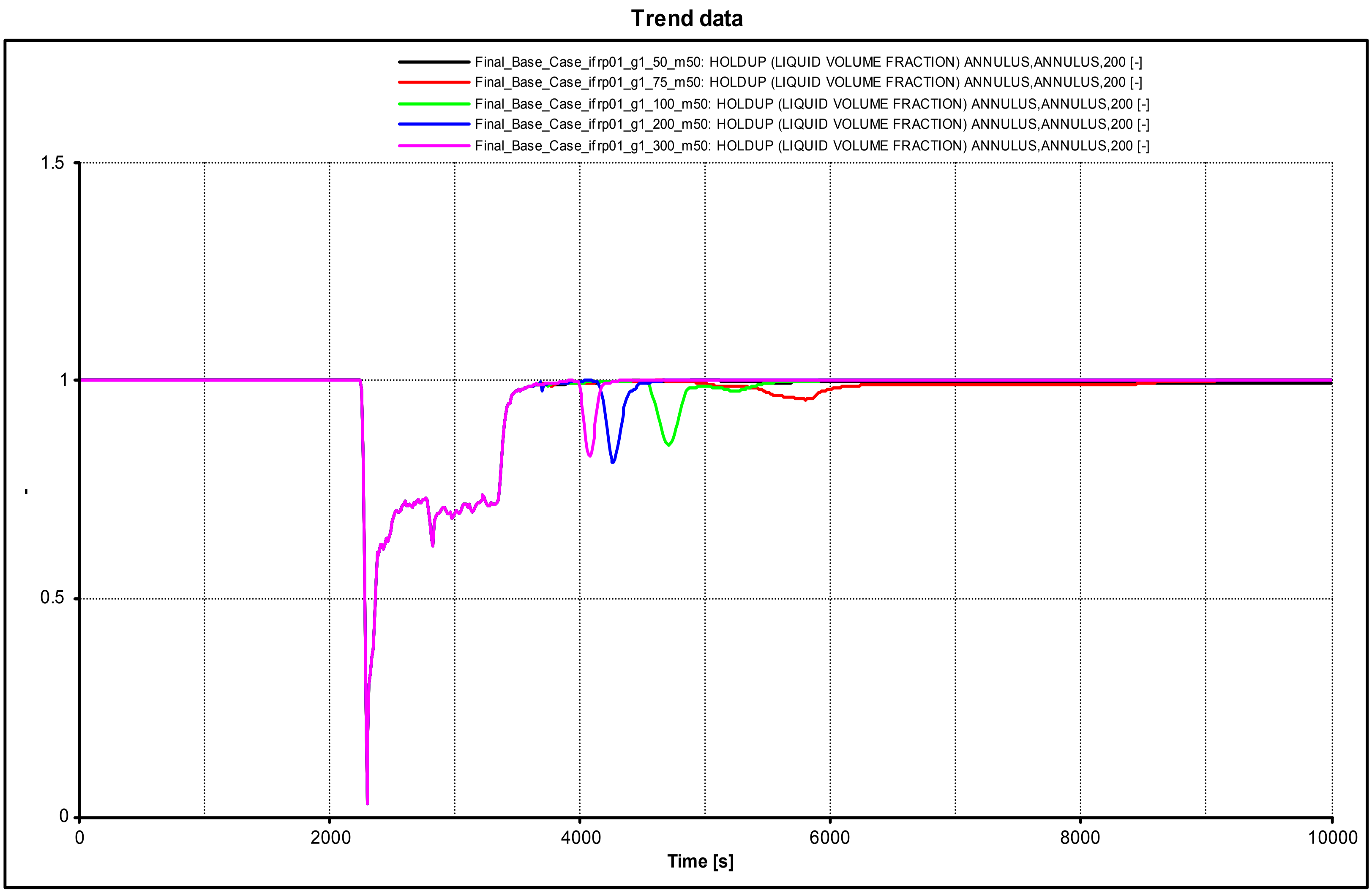

Fig. 17—Liquid holdup at outlet of annulus, Geometry 1, inclination -5°, circulation rate 50, 75, 100, 200, & 300 GPM.

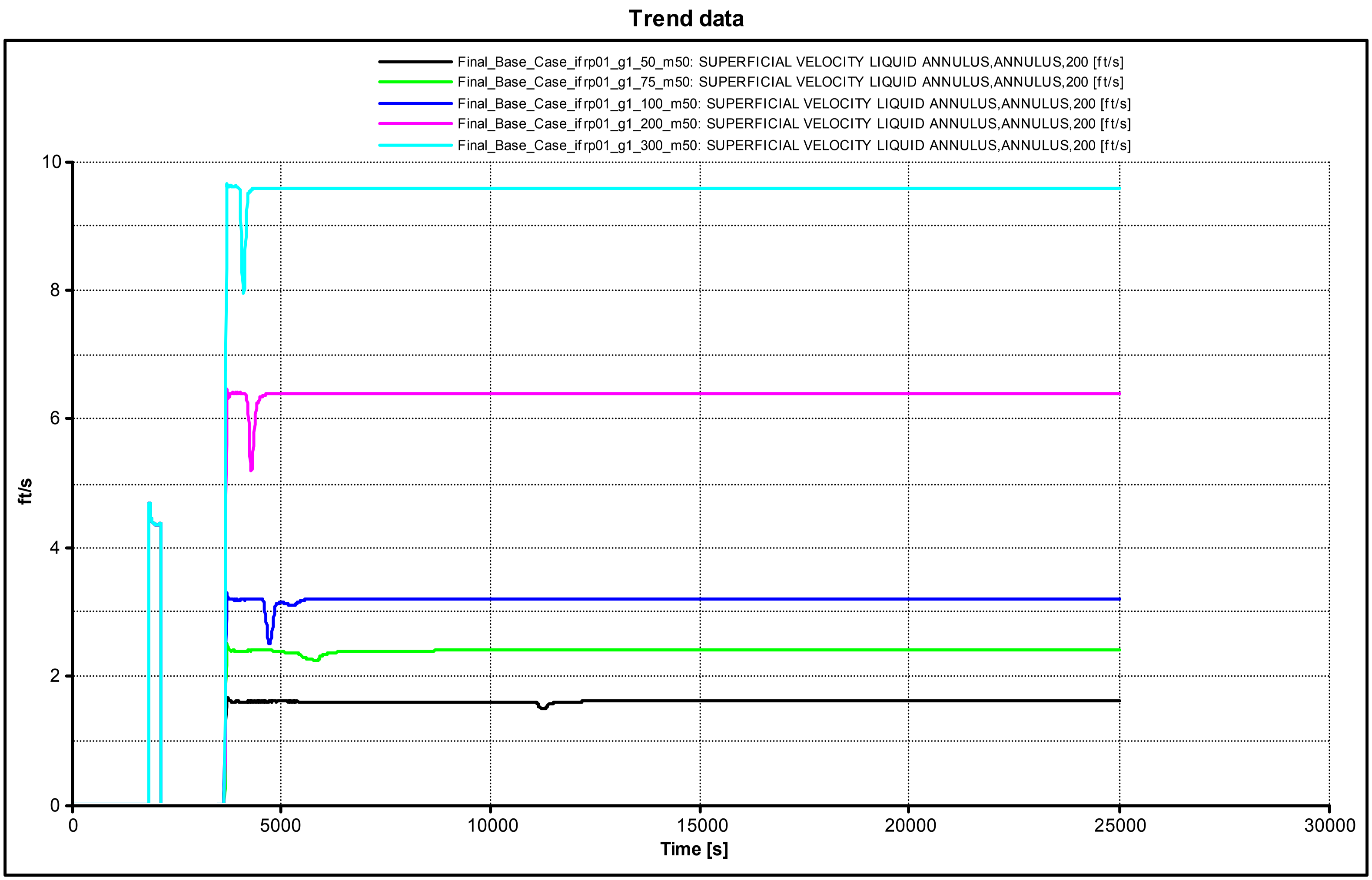

Fig. 18—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination -5°, circulation rate 50, 75, 100, 200, & 300 GPM.

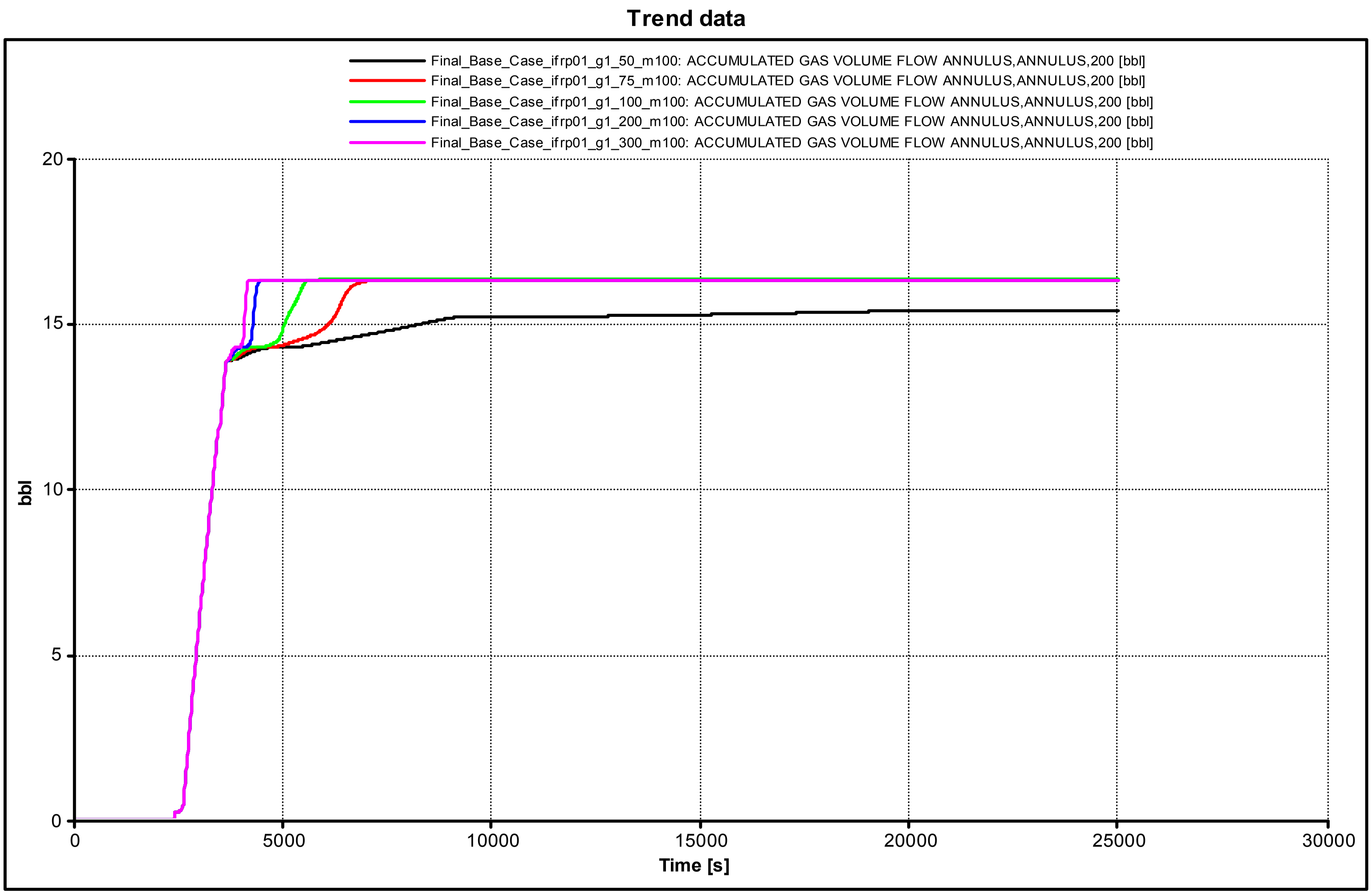

Fig. 19—Accumulated gas out at outlet of annulus, Geometry 1, inclination -10°, circulation rate 50, 75, 100, 200, & 300 GPM.

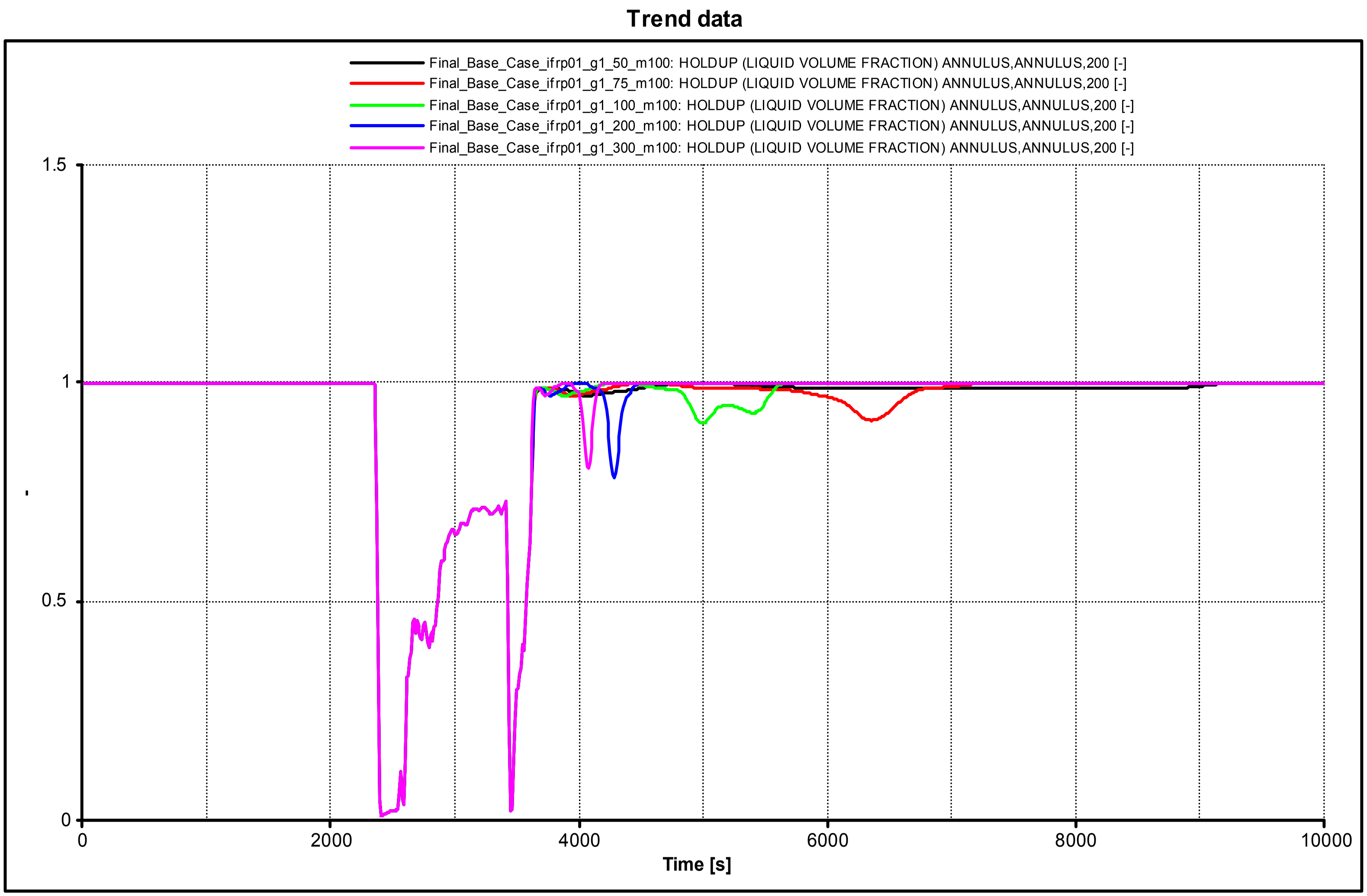

Fig. 20—Liquid holdup at outlet of annulus, Geometry 1, inclination -10°, circulation rate 50, 75, 100, 200, & 300 GPM.

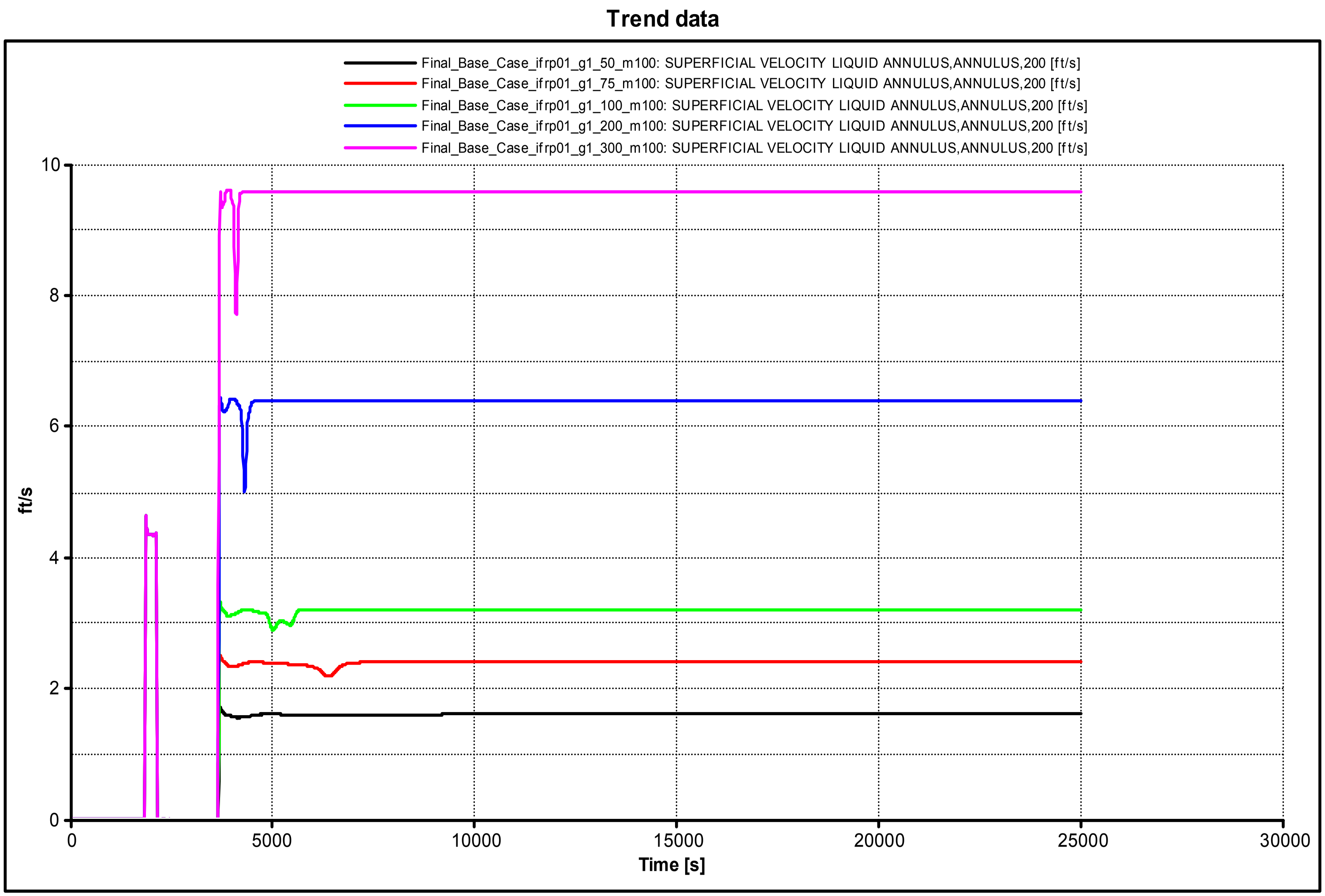

Fig. 21—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination -10°, circulation rate 50, 75, 100, 200, & 300 GPM.

Geometry 2

Geometry 2 consists of a 7.875-in. hole size with 5 in. outer-diameter drillpipe. The effective annular area is 29.07 sq. in. **Figs. 22 to 36** illustrate the results for the five inclinations.

Inclination 10°

For Geometry 2, considerably higher circulation rates were needed to displace the kick than for Geometry 1. In Fig. 22 at a circulation rate of 250 GPM, the gas kick is not displaced. Increasing the rate to 275 GPM allows the gas kick to be removed from the upwardly inclined horizontal section. For the rate of 275 GPM, the simulated kick removal time was approximately 2.11 hrs. This is considerably more than the calculated piston-like displacement value of 0.229 hrs. Again, the presence of the gas kick's buoyancy forces can be seen. The higher circulation rates of 350 and 400 GPM more efficiently displace the kick and come closer to the piston-like displacement times. The widths of the downward protruding humps of the liquid holdup curves in Fig. 23 represent the efficiency of the kick removal. The higher the circulation rate is, the narrower the hump and the lower the liquid holdup value. It is also worth noting that the gas kick is being transported as a continuous unit. Fig. 242 depicts liquid superficial velocities. A superficial velocity of 3 ft/sec is required to displace the gas kick. This value is close to the superficial velocity needed in Geometry 1.

Inclination 5°

Figs. 25 to 27 represent the data for an inclination of 5º above horizontal. The same conclusions can be reached for this inclination as were reached for the 10º case.

However, the curves in Fig. 25 are shifted farther to the left than in Fig. 22. This reflects the decrease in gas-kick buoyancy forces that result from the lower inclination angle.

Inclination 0°

For a completely horizontal inclination, the gas kick was efficiently removed at all simulated circulation rates. Fig. 28 shows smooth, similar, and offset curves. The kick removal times are close to a piston-like displacement model for all circulation rates. Fig. 29 shows smoothly increasing and decreasing liquid-holdup curves. This is consistent with a stratified flow regime.

Inclination -5°

For an inclination of 5º below horizontal, the gas migrates up the annulus before circulation beings. This effect is responsible for the identical overlapping portions of the curves in Fig. 31. The nonoverlapping portion of the curves is a result of the migrating up the drillpipe. Once circulation begins, the kick is displaced from the drillpipe. The shape or slope of the top portion of these curves is dependent on the circulation rate. The effect of the gas in the drillpipe may also be seen in Fig. 32 and Fig. 33.

Inclination -10°

For an inclination of 10º below horizontal, the results were similar to the results of the case with an inclination of 5º below horizontal. Figs. 34 to 36 depict the results.

300 gpm

Trend data

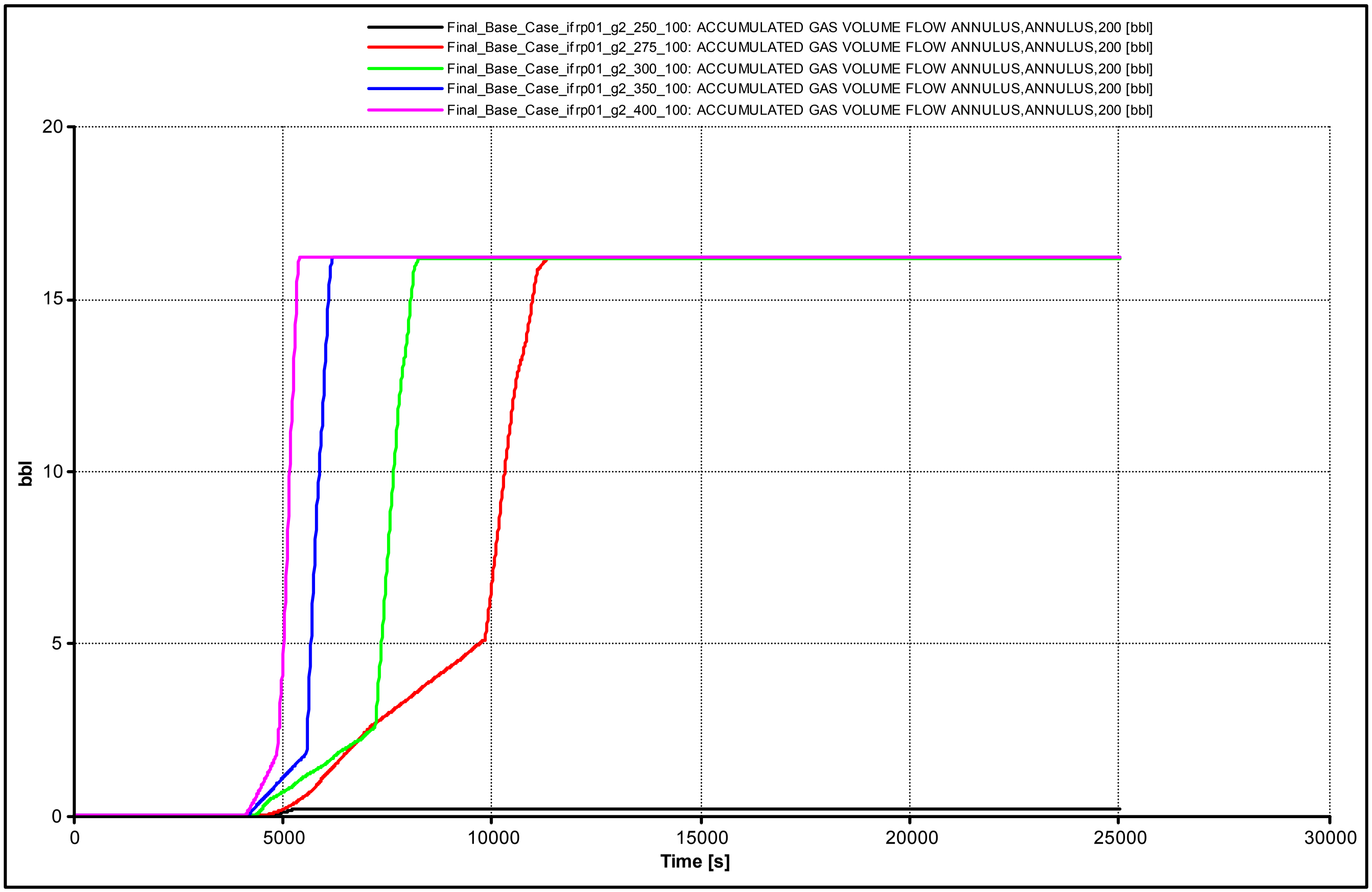

Fig. 22—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250, 275, 300, 350, & 400 GPM.

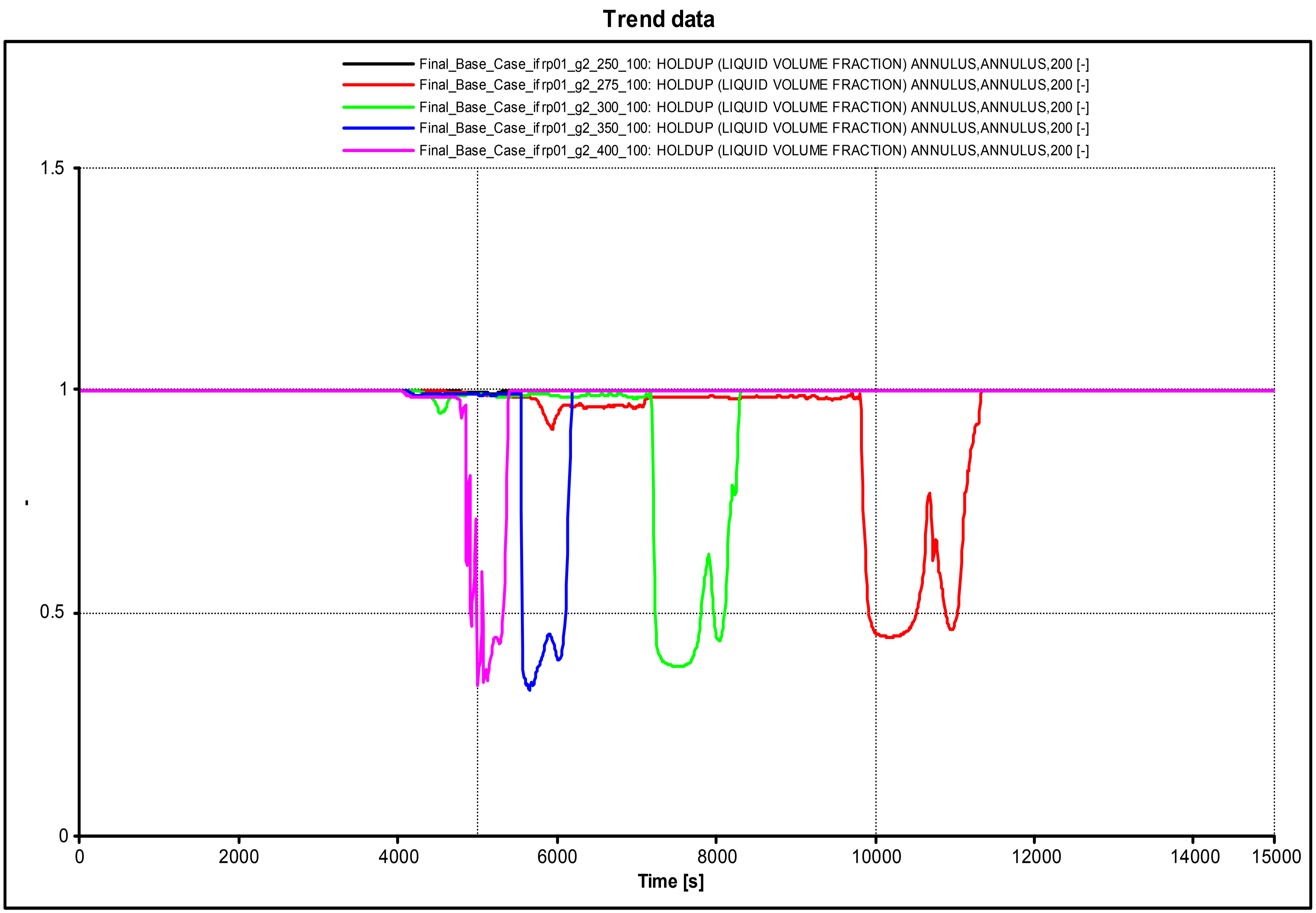

Fig. 23—Liquid holdup at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250, 275, 300, 350, & 400 GPM.

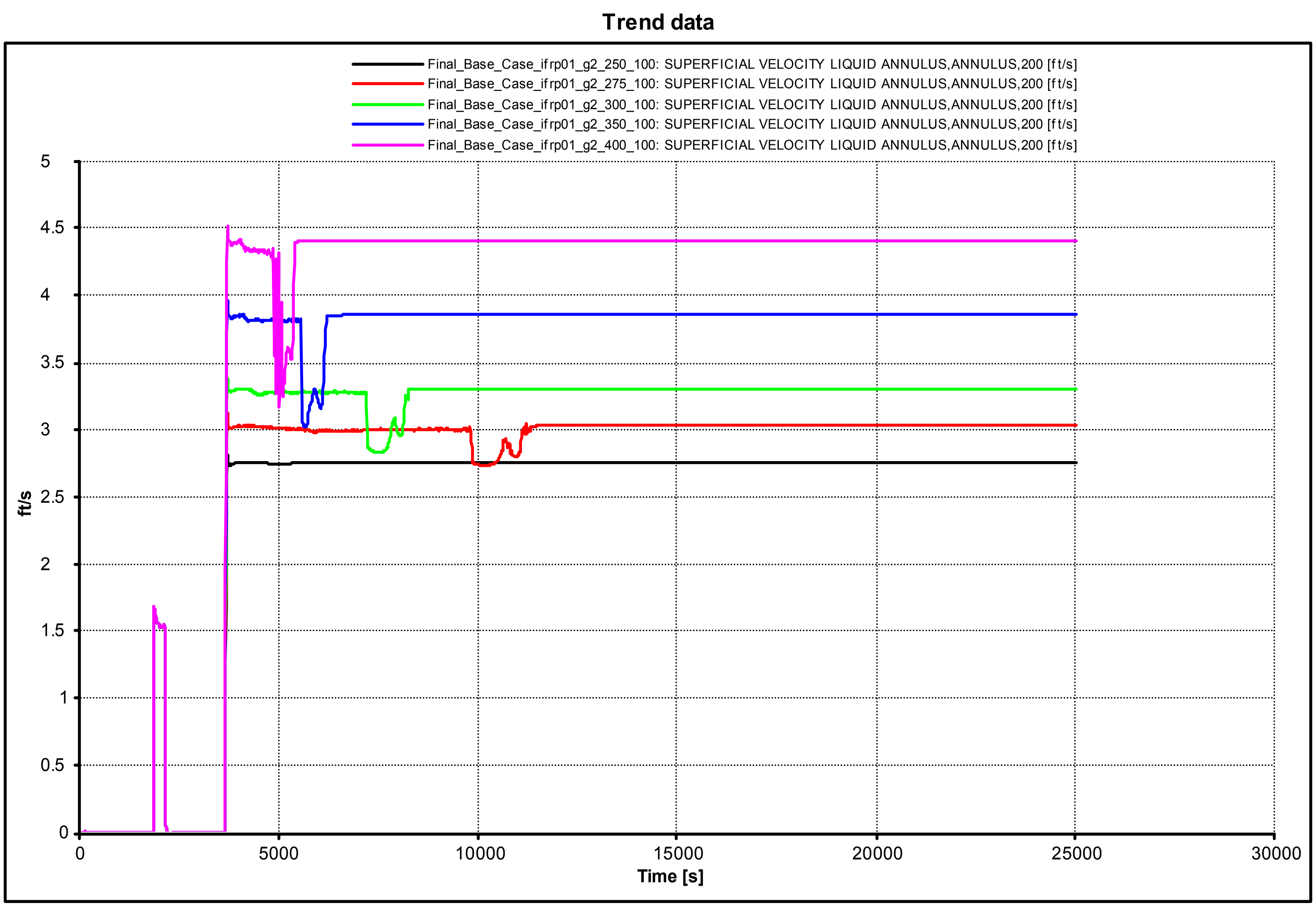

Fig. 24—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250, 275, 300, 350, & 400 GPM.

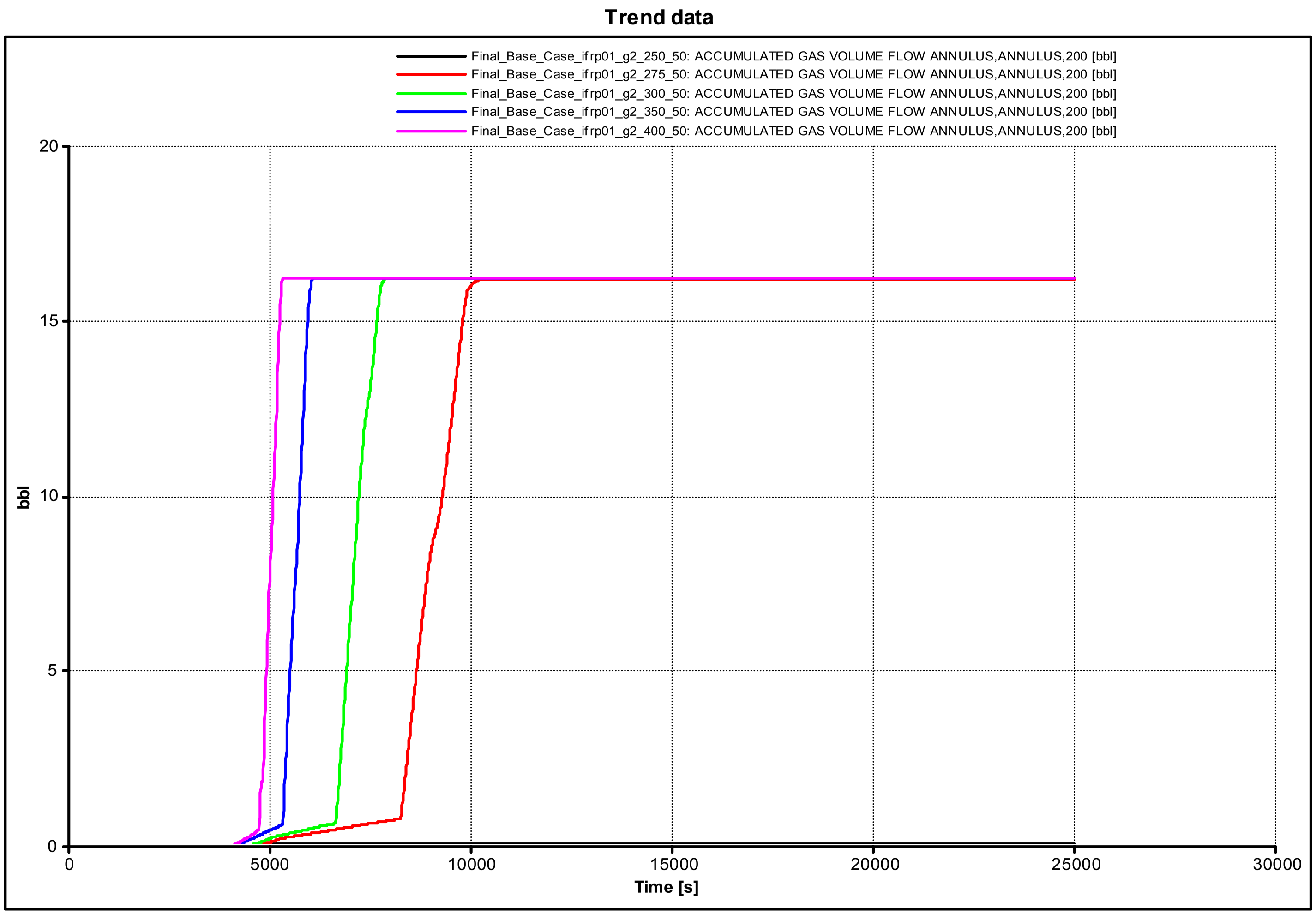

Fig. 25—Accumulated gas out at outlet of annulus, Geometry 2, inclination 5°, circulation rate 250, 275, 300, 350, & 400 GPM.

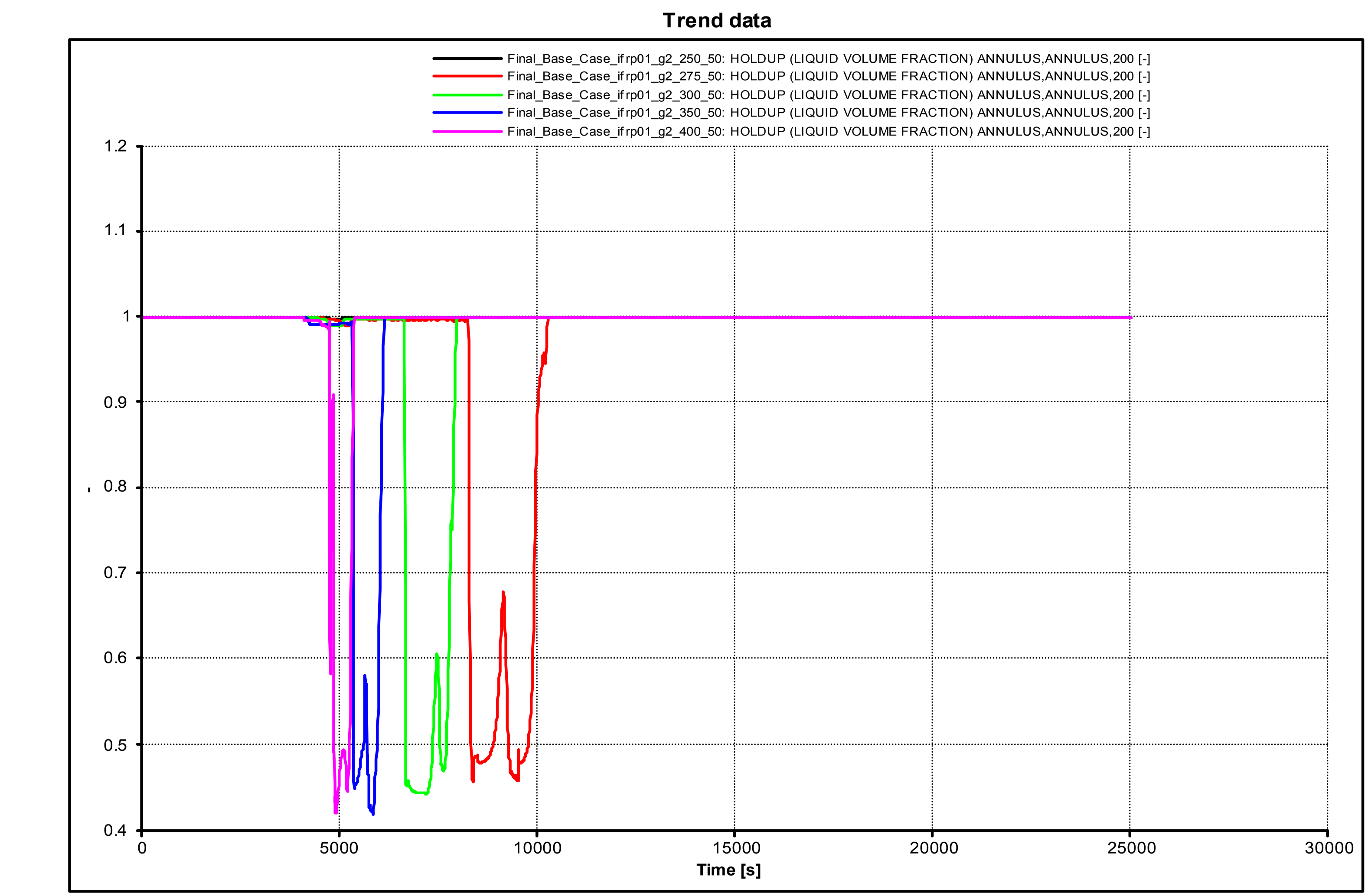

Fig. 26—Liquid holdup at outlet of annulus, Geometry 2, inclination 5°, circulation rate 250, 275, 300, 350, & 400 GPM.

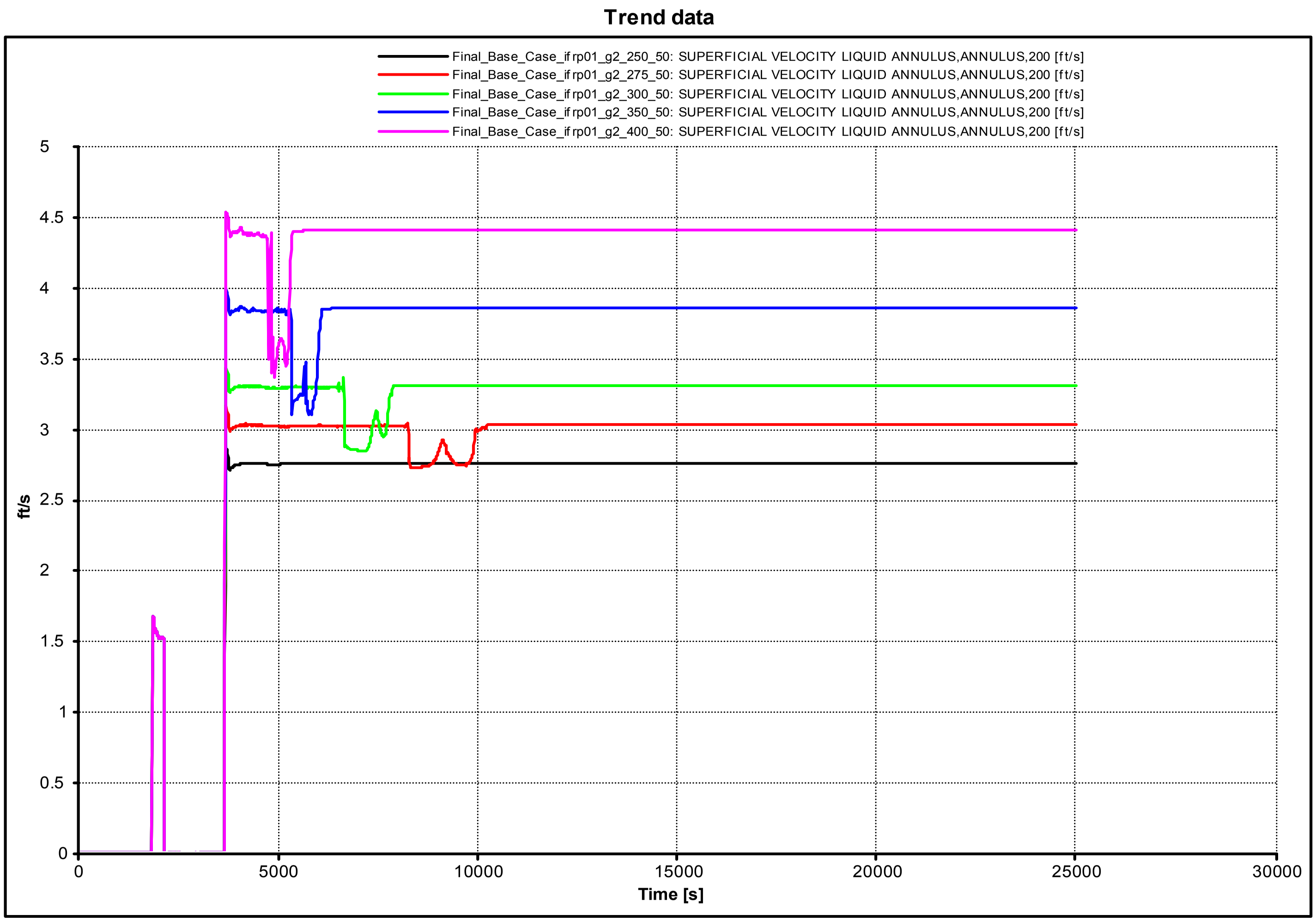

Fig. 27—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 5°, circulation rate 250, 275, 300, 350, & 400 GPM.

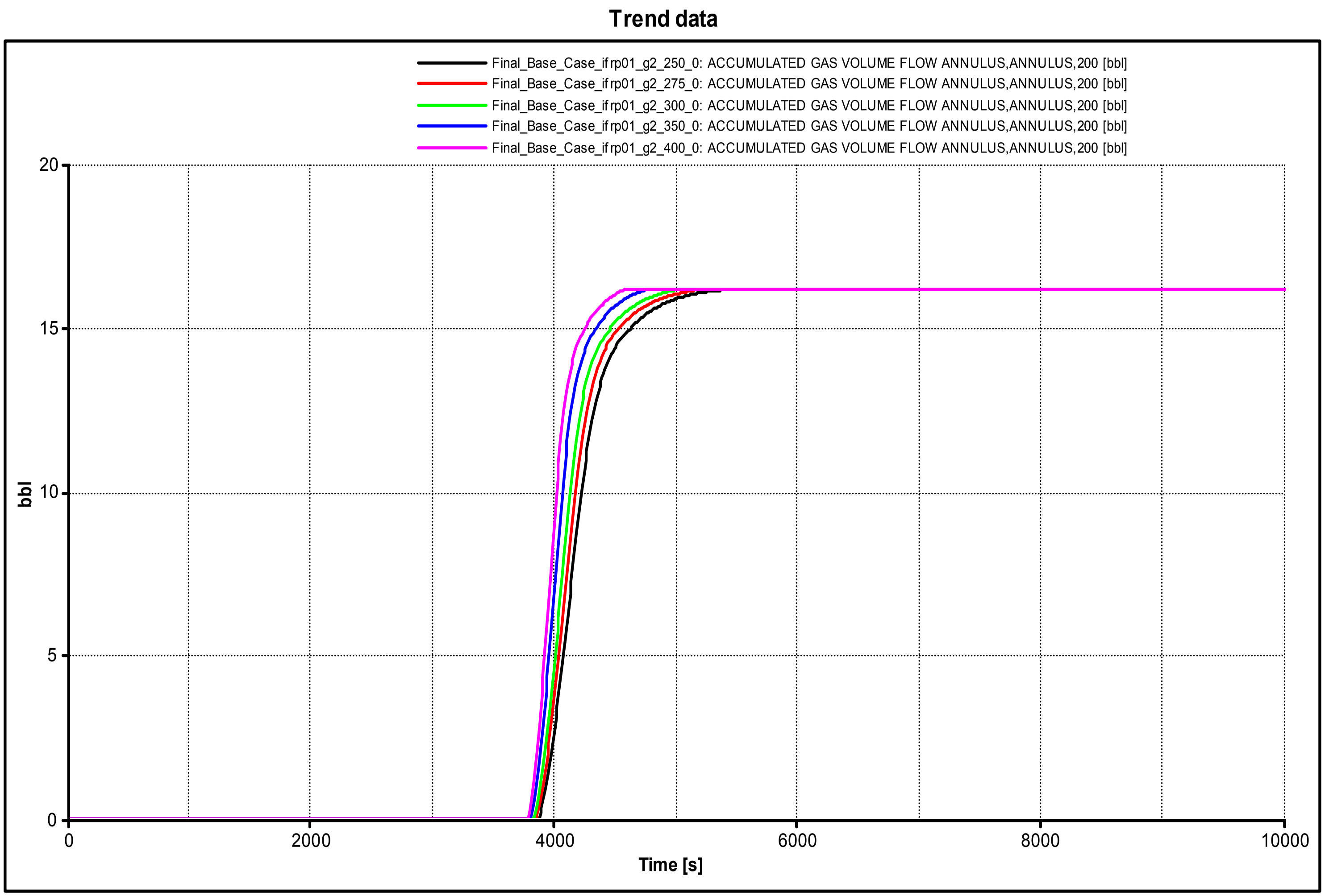

Fig. 28—Accumulated gas out at outlet of annulus, Geometry 2, inclination 0°, circulation rate 250, 275, 300, 350, & 400 GPM.

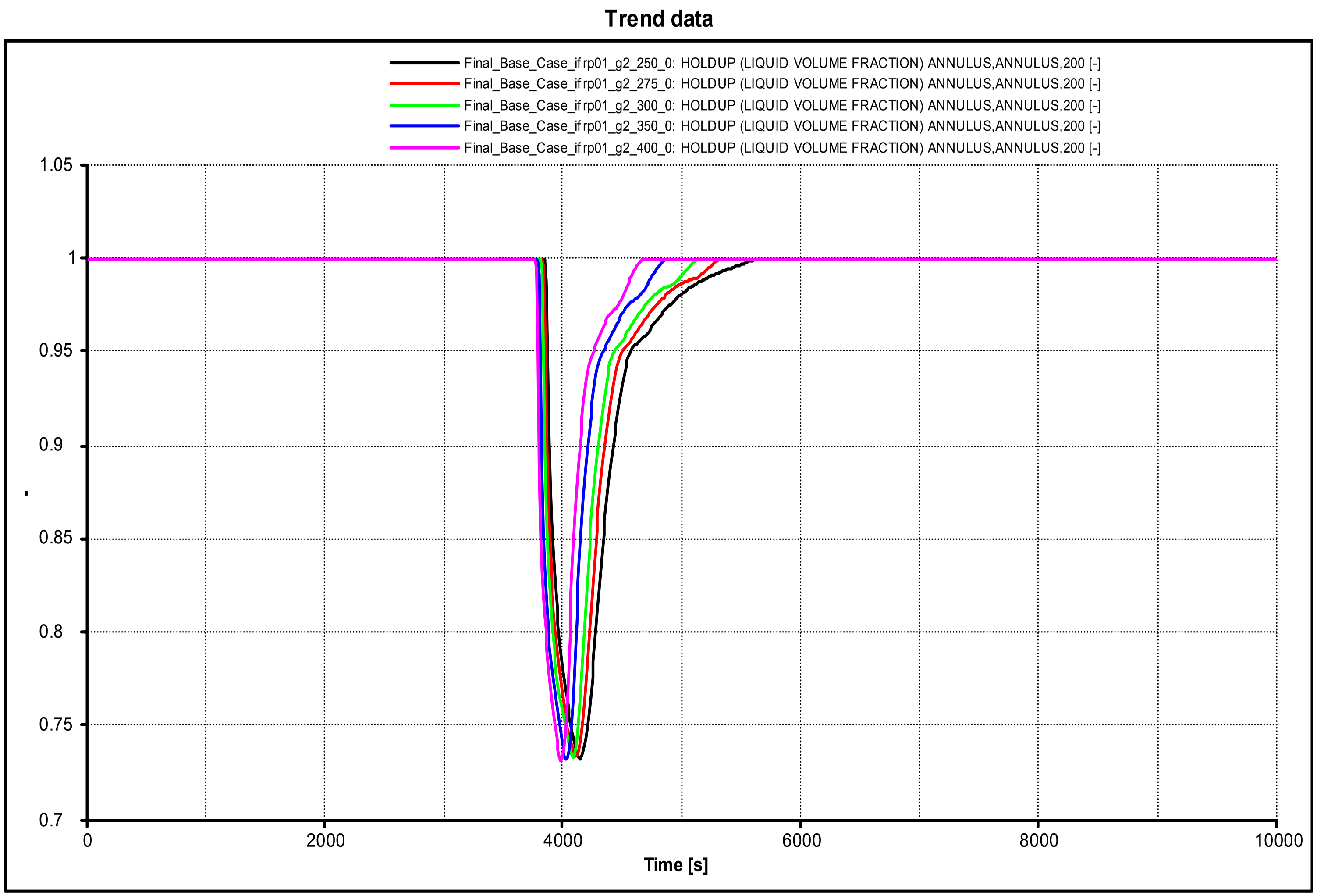

Fig. 29—Liquid holdup at outlet of annulus, Geometry 2, inclination 0°, circulation rate 250, 275, 300, 350, & 400 GPM.

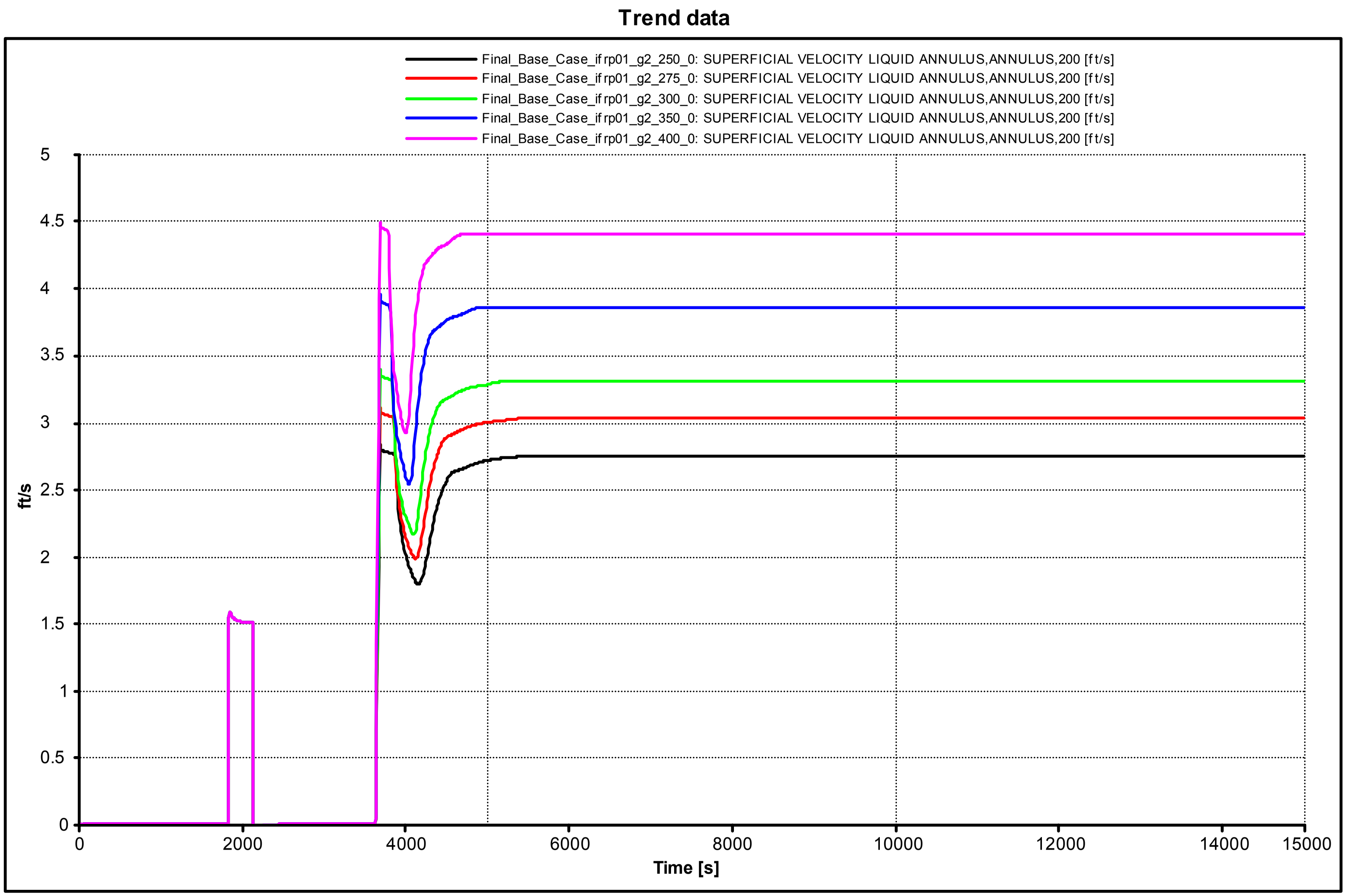

Fig. 30—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 0°, circulation rate 250, 275, 300, 350, & 400 GPM.

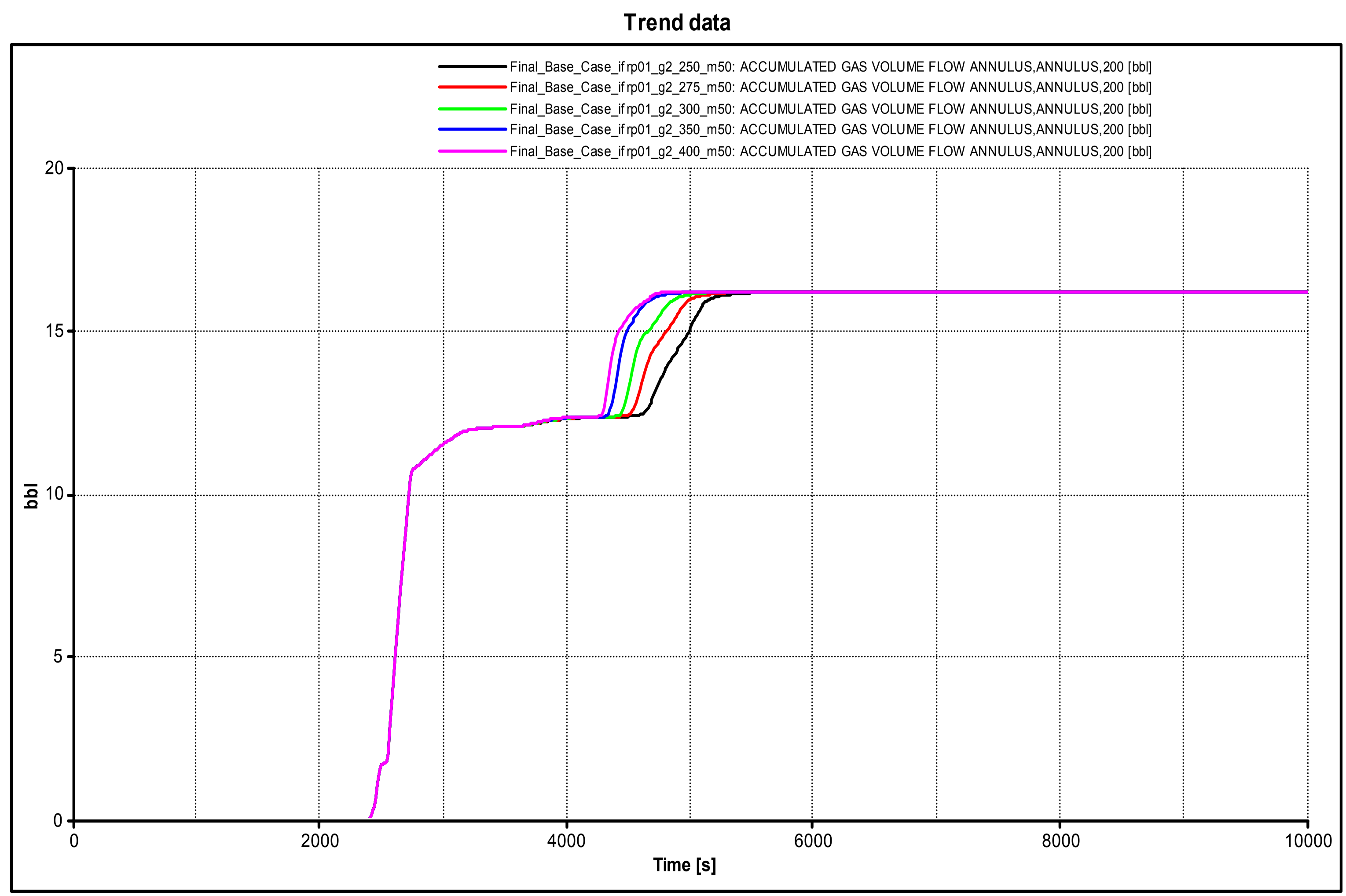

Fig. 31—Accumulated gas out at outlet of annulus, Geometry 2, inclination -5°, circulation rate 250, 275, 300, 350, & 400 GPM.

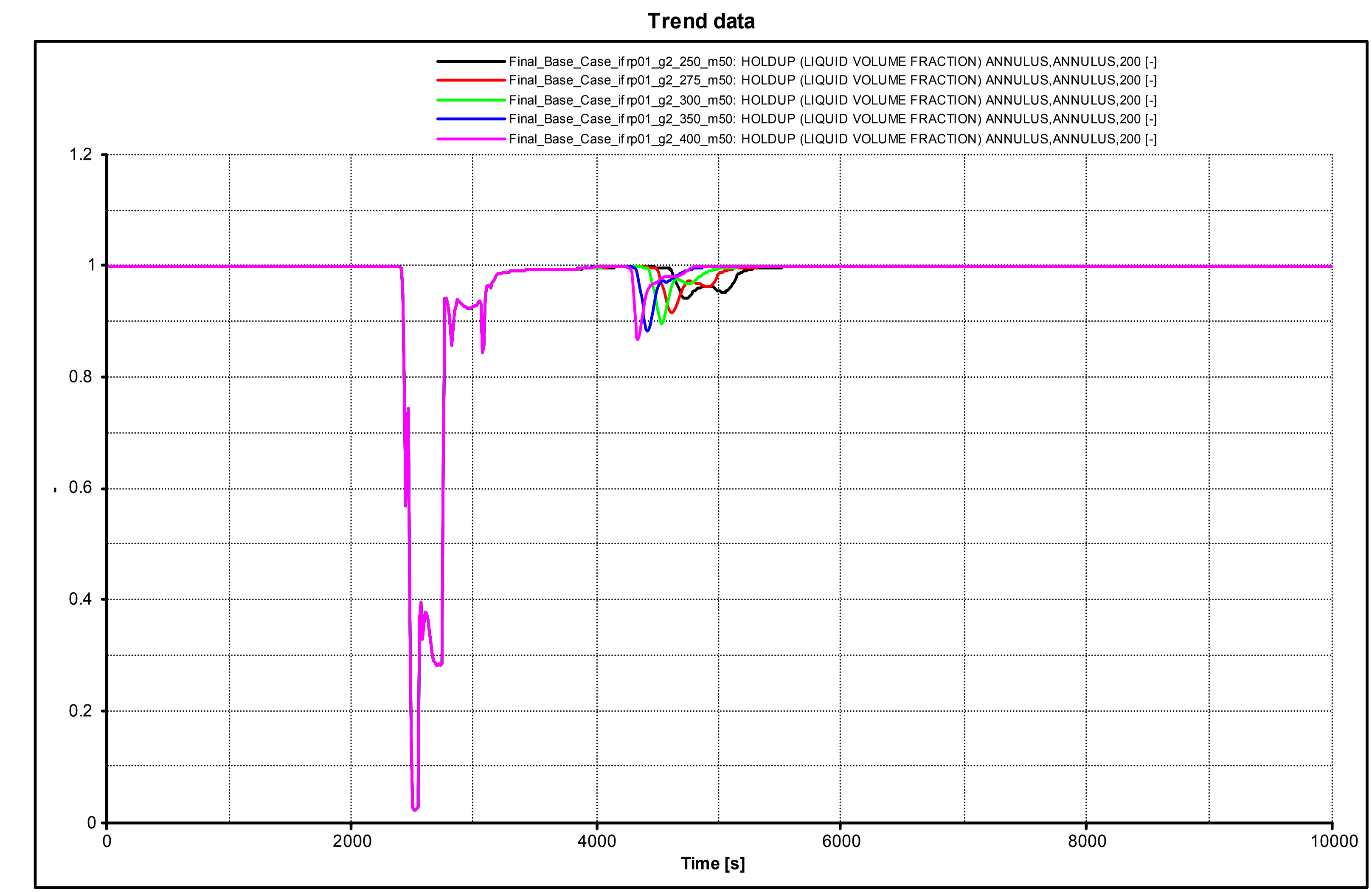

Fig. 32—Liquid holdup at outlet of annulus, Geometry 2, inclination -5°, circulation rate 250, 275, 300, 350, & 400 GPM.

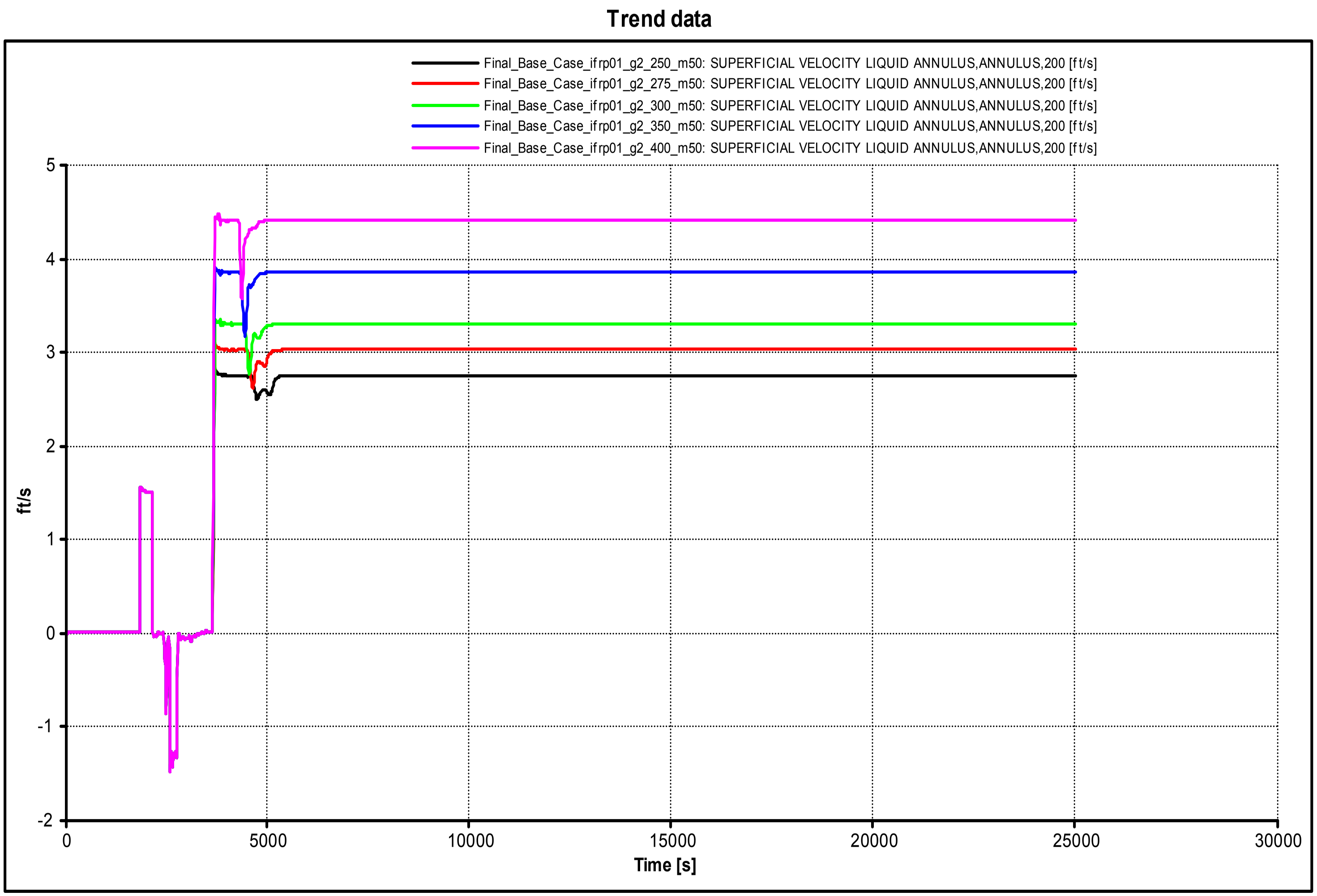

Fig. 33—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination -5°, circulation rate 250, 275, 300, 350, & 400 GPM.

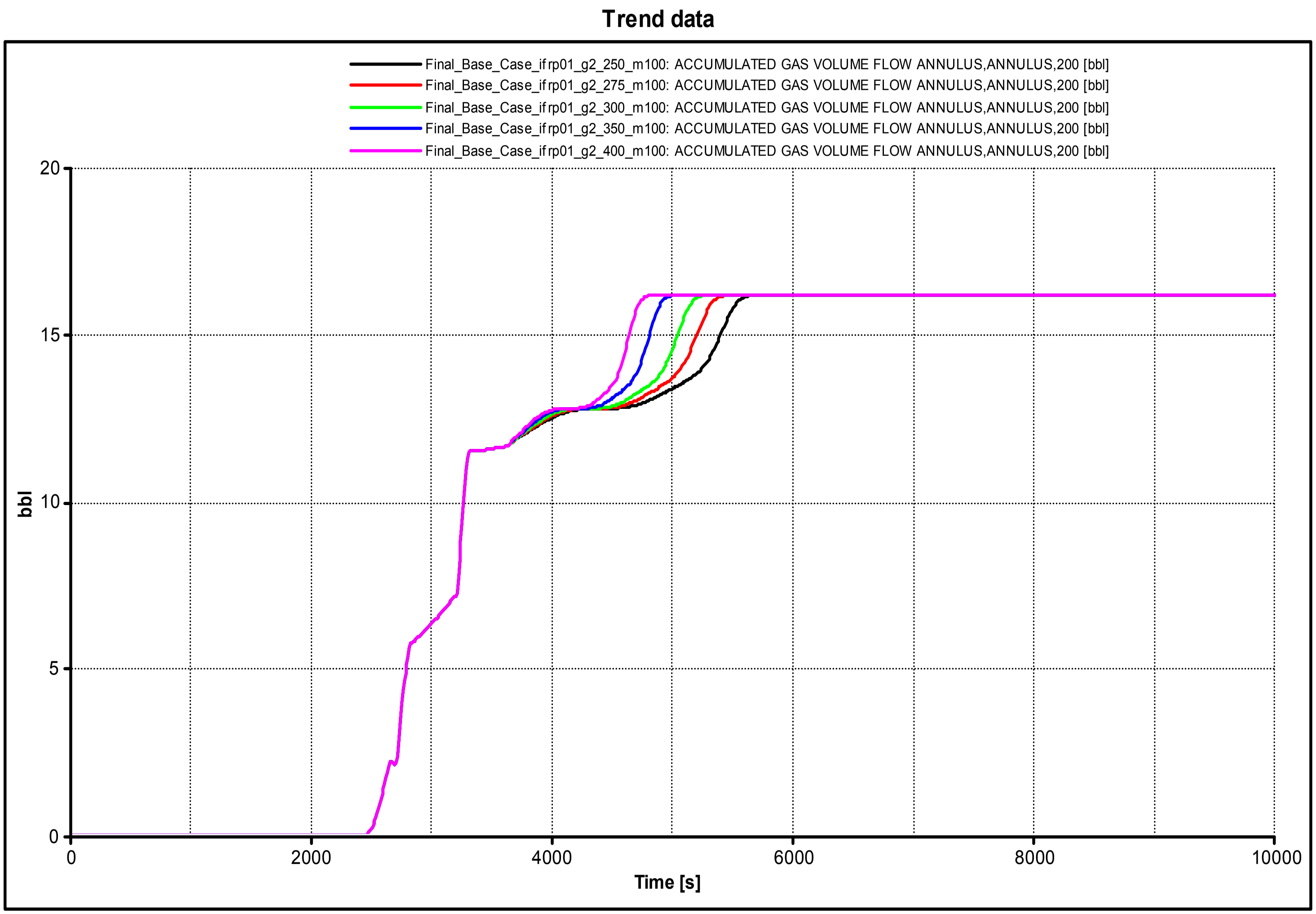

Fig. 34—Accumulated gas out at outlet of annulus, Geometry 2, inclination -10°, circulation rate 250, 275, 300, 350, & 400 GPM.

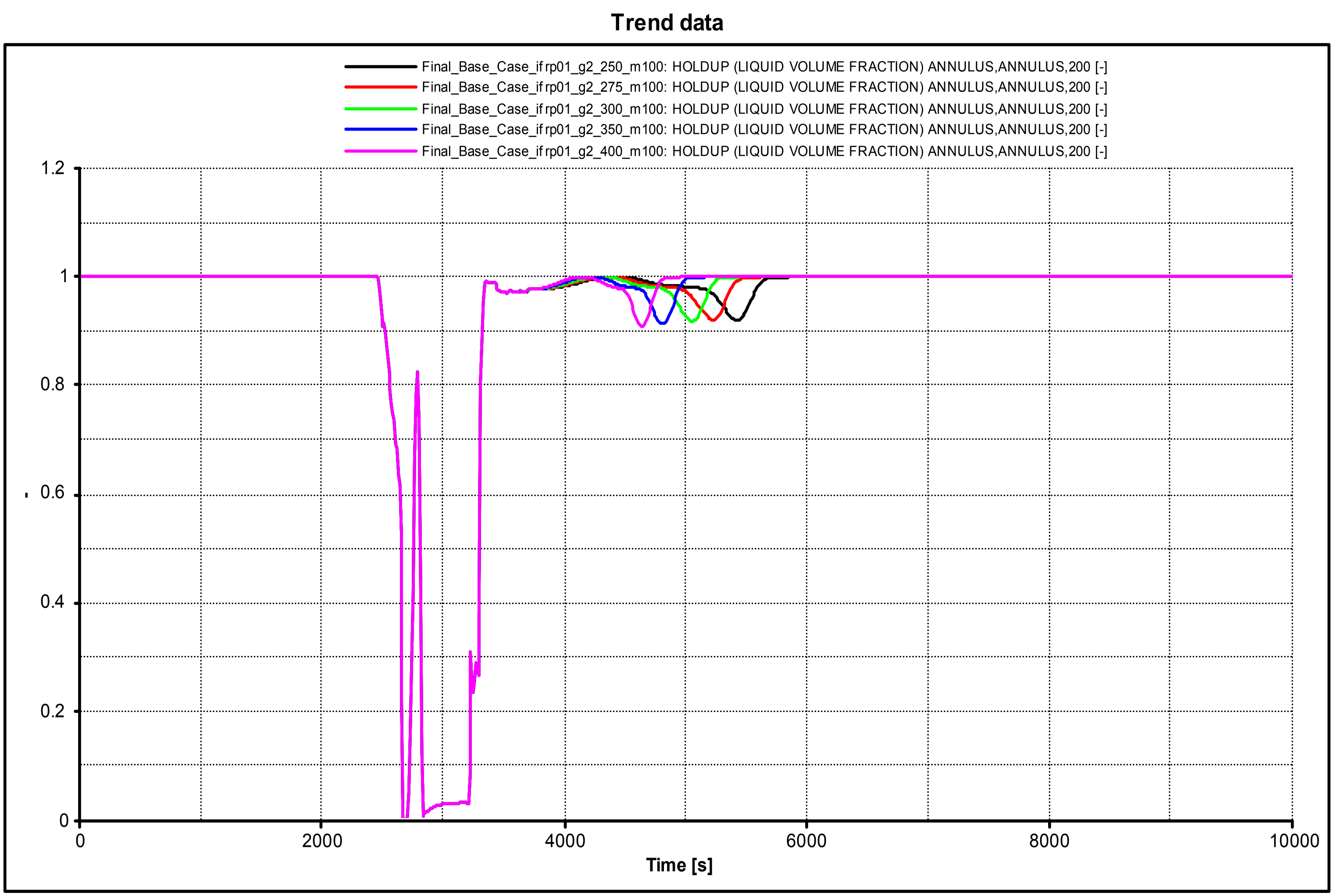

Fig. 35—Liquid holdup at outlet of annulus, Geometry 2, inclination -10°, circulation rate 250, 275, 300, 350, & 400 GPM.

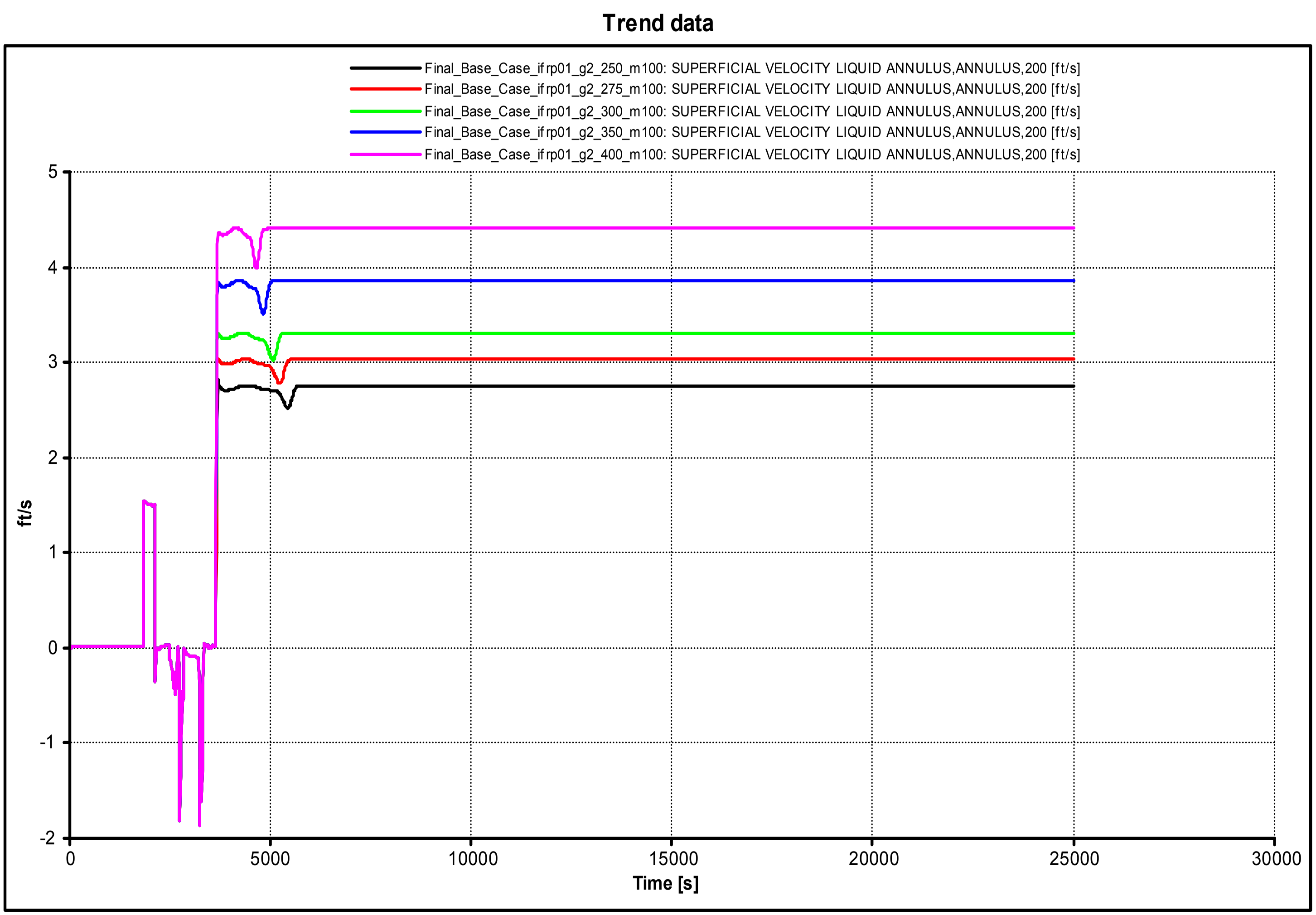

Fig. 36—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination -10°, circulation rate 250, 275, 300, 350, & 400 GPM.

Geometry 3

Geometry 3 consists of a 9.875-in. hole size with 5-in. outer-diameter drillpipe. The effective annular area is 56.95 sq. in. **Figs. 37 to 51** illustrate the results for the five inclinations.

Inclination 10°

For Geometry 3, extremely high circulation rates were required to transport the gas kick. In Fig. 37 a circulation rate of 300 gpm was insufficient in removing the kick. Rates of 600 and 700 GPM efficiently removed the kick from the horizontal section. Fig. 38 illustrates the liquid-holdup curves. Fig. 39 shows that a superficial velocity of 3.3 ft/s is needed to effectively remove the gas influx. Interestingly, this value is only slightly higher than the value required for Geometry 2.

Inclination 5°

Figs. 40-42 represent the data for an inclination of 5º above horizontal. The same conclusions can be reached for this inclination as were reached for the 10º case. However, the curves in Fig. 40 are shifted to the left more than in Fig. 37. This reflects the decrease in gas-kick buoyancy forces resulting from the lower inclination angle.

Inclination 0°

For a completely horizontal inclination, the gas kick was efficiently removed at all simulated circulation rates. Fig. 43 shows smooth, similar, and offset curves. The kick removal times are close to a piston-like displacement model for all circulation rates. Fig. 44 shows smoothly increasing and decreasing liquid holdup curves, is consistent with a stratified flow regime.

Inclination -5°

For an inclination of 5º below horizontal, the gas begins migrating up the annulus instantaneously. When circulation begins at 3,600 seconds, the majority of the gas kick has left the horizontal section. During the gas-kick influx, a small amount of gas begins to migrate up the drillpipe instead of the annulus. Once circulation begins, the gas is displaced from the drillpipe into the annulus and removed from the annular horizontal section. This phenomenon is depicted in Fig. 46 by the irregular top portion of each curve. The shape or slope of the top portion of these curves depends on the circulation rate. The effect of the gas in the drillpipe may also be seen in Fig. 47 and Fig. 48.

Inclination -10°

For an inclination of 10º below horizontal, the results were similar to the results of the case with an inclination of 5º below horizontal. Figs. 49 to 51 depict the results.

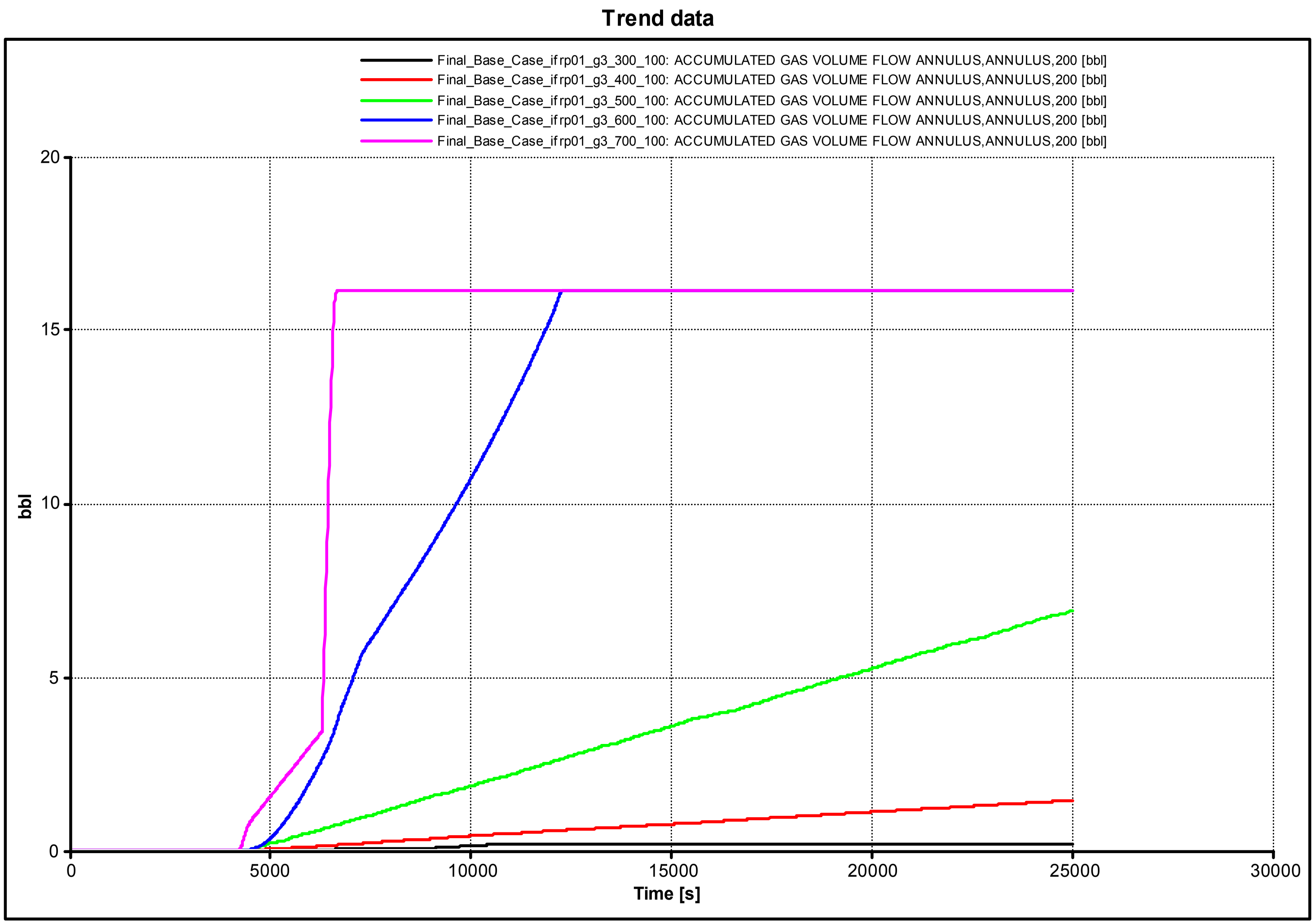

Fig. 37—Accumulated gas out at outlet of annulus, Geometry 3, inclination 10°, circulation rate 300, 400, 500, 600 & 700 GPM.

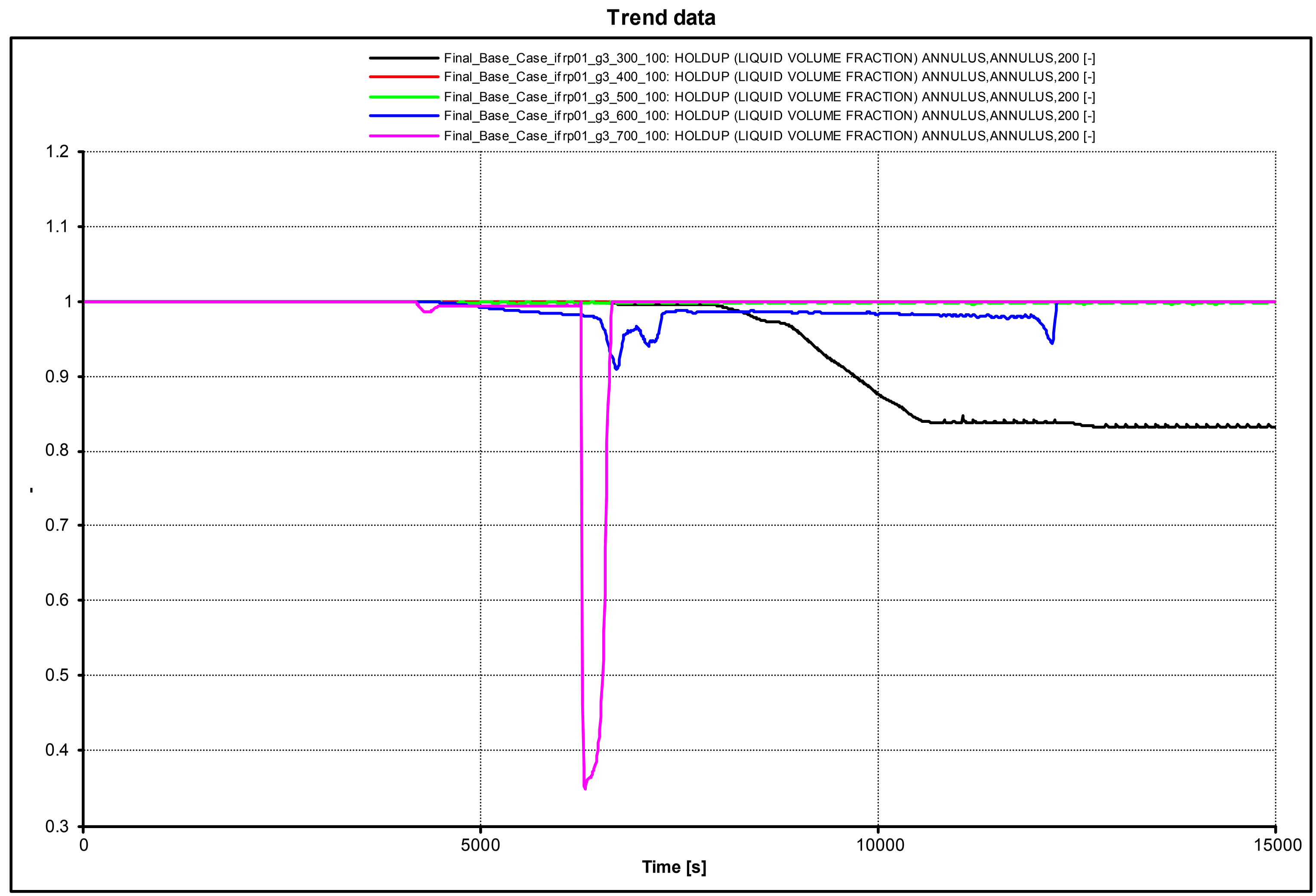

Fig. 38—Liquid holdup at outlet of annulus, Geometry 3, inclination 10°, circulation rate 300, 400, 500, 600, & 700 GPM.

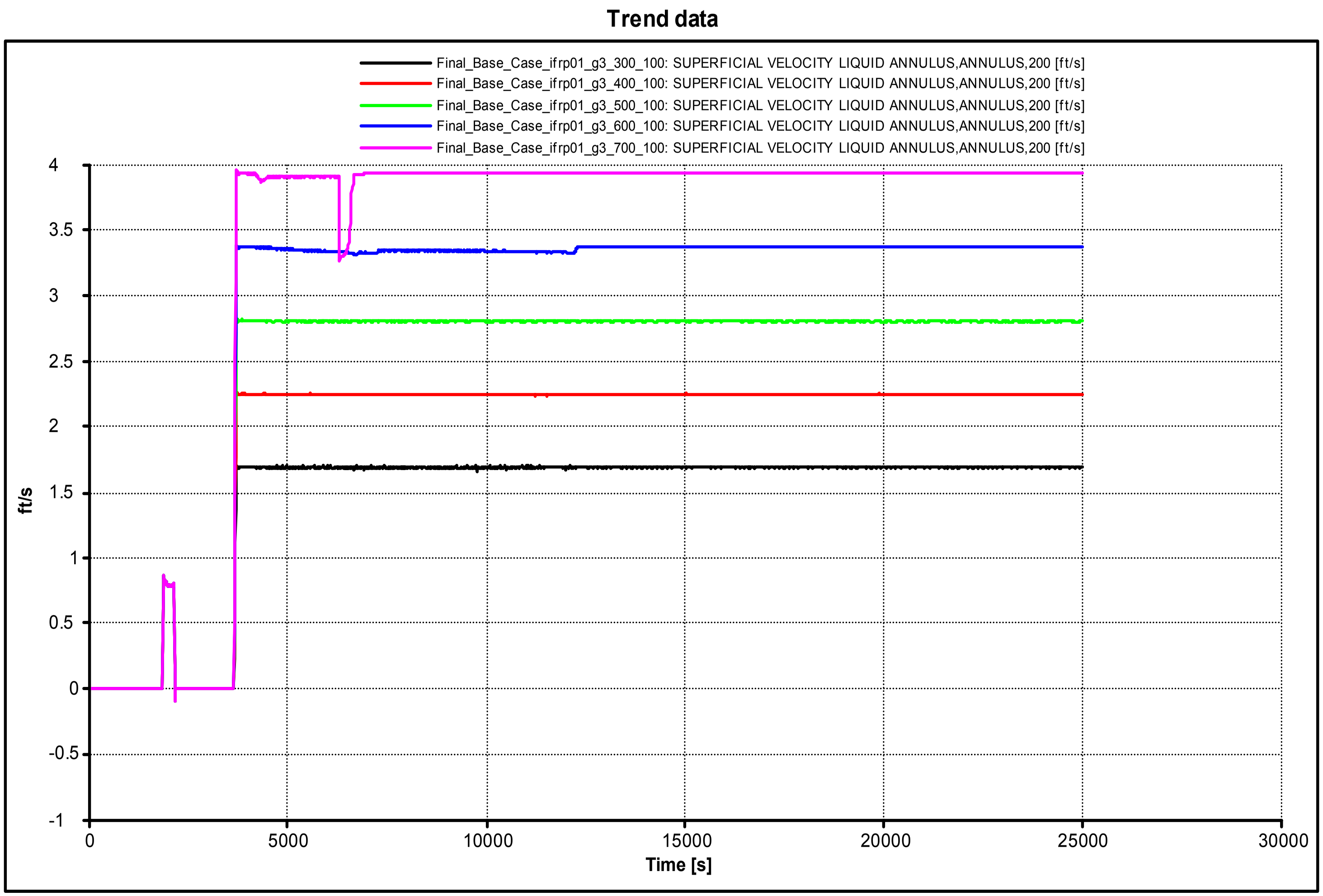

Fig. 39—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 10°, circulation rate 300, 400, 500, 600, & 700 GPM.

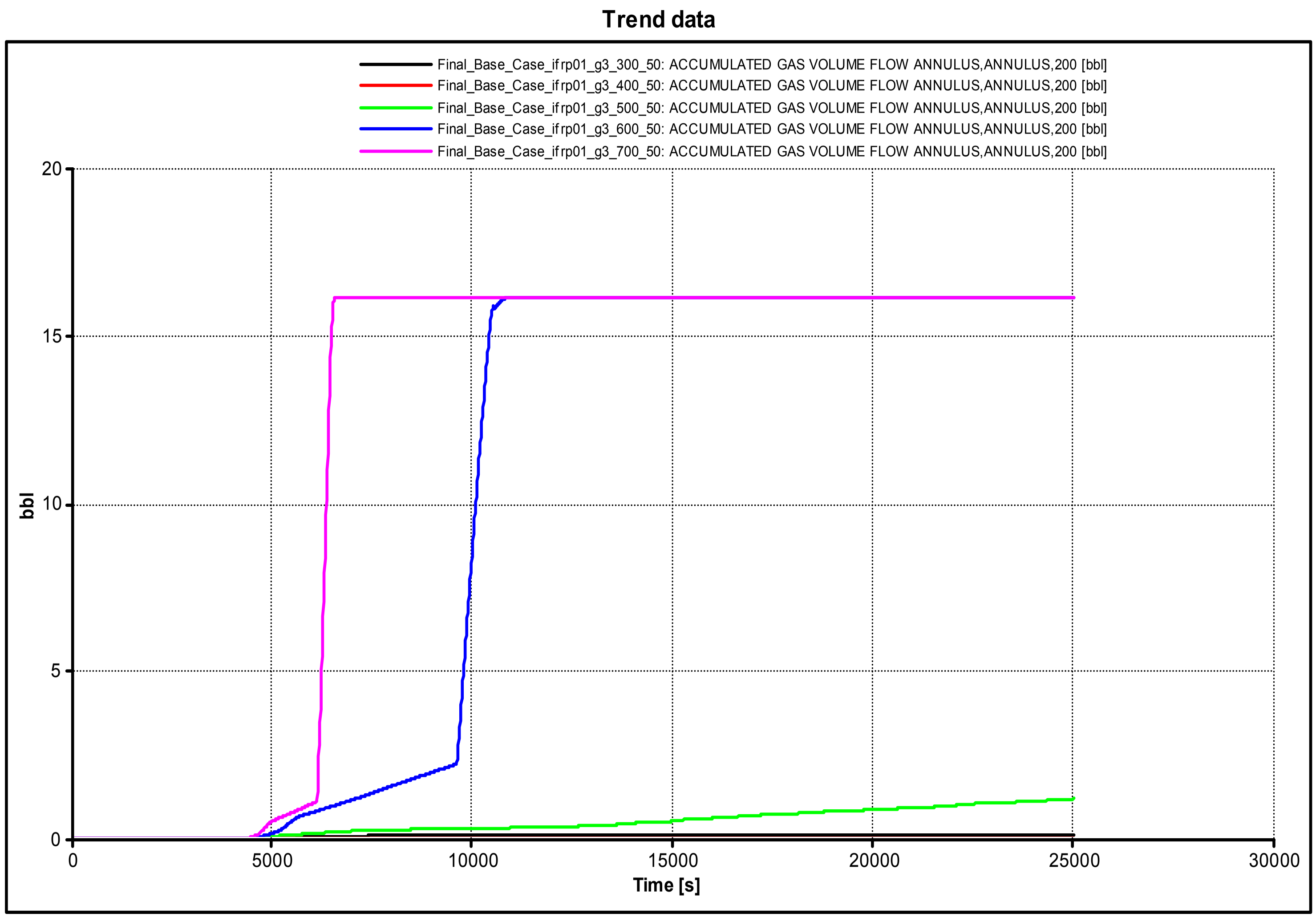

Fig. 40—Accumulated gas out at outlet of annulus, Geometry 3, inclination 5°, circulation rate 300, 400, 500, 600 & 700 GPM.

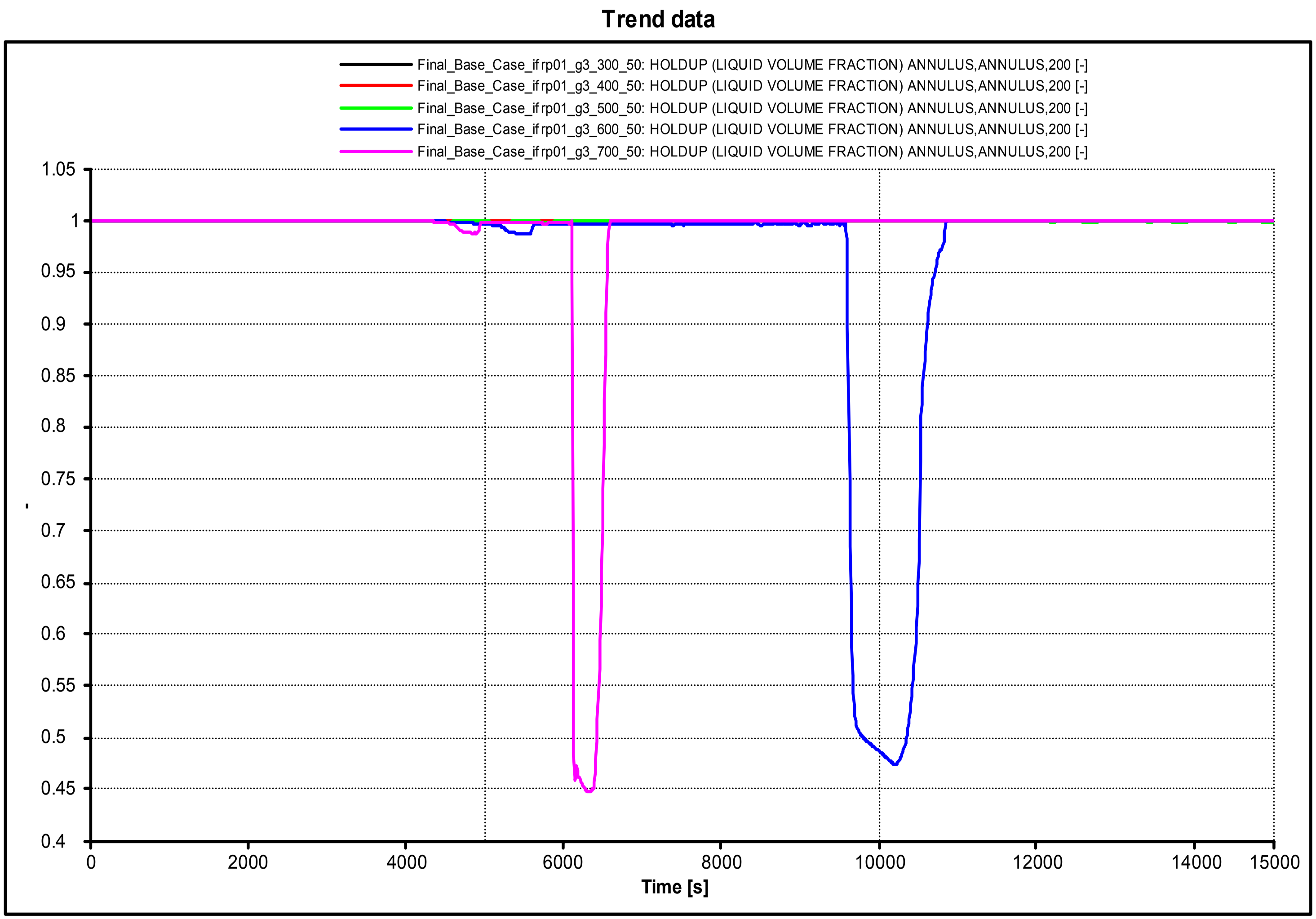

Fig. 41—Liquid holdup at outlet of annulus, Geometry 3, inclination 5°, circulation rate 300, 400, 500, 600, & 700 GPM.

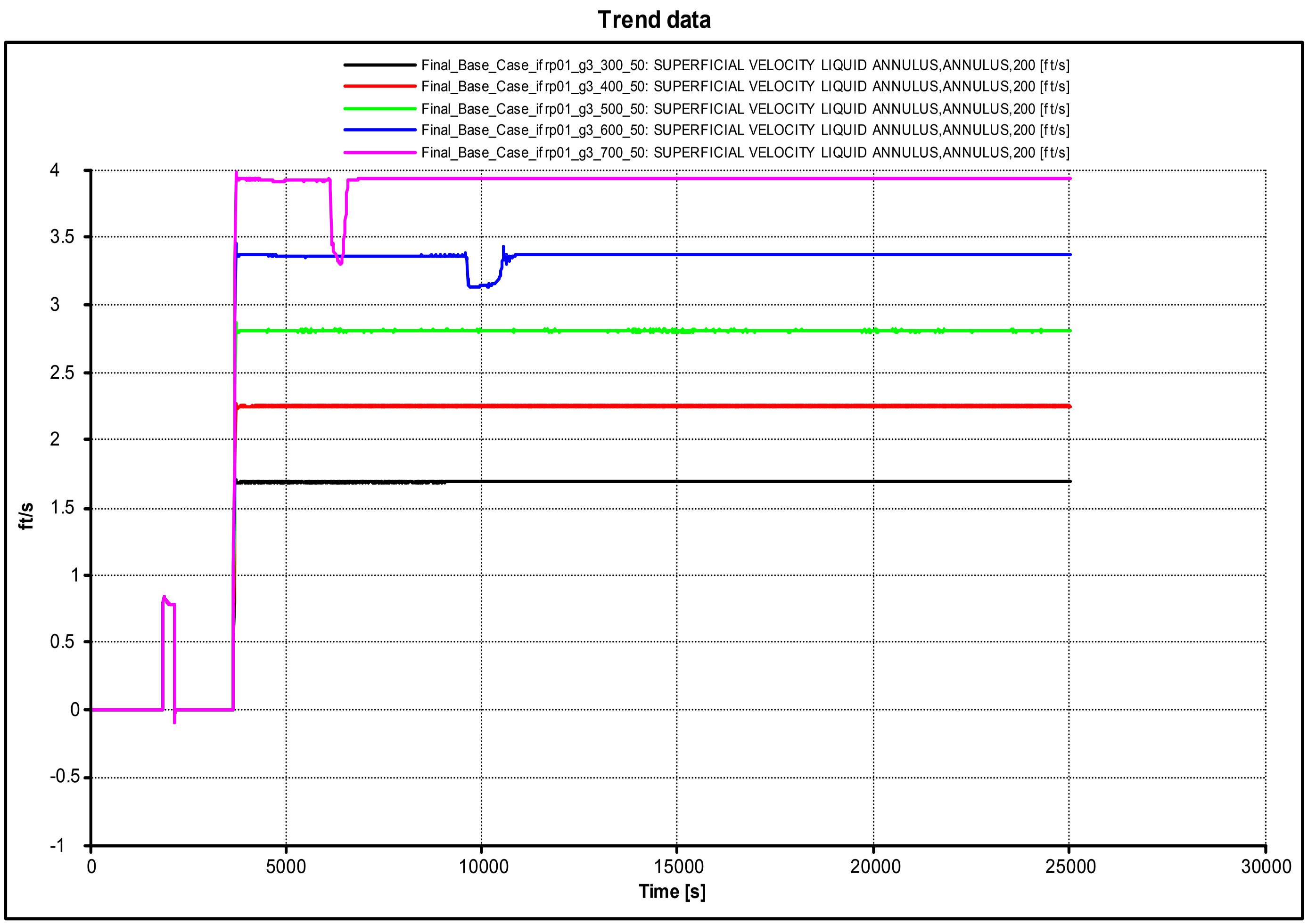

Fig. 42—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 5°, circulation rate 300, 400, 500, 600, & 700 GPM.

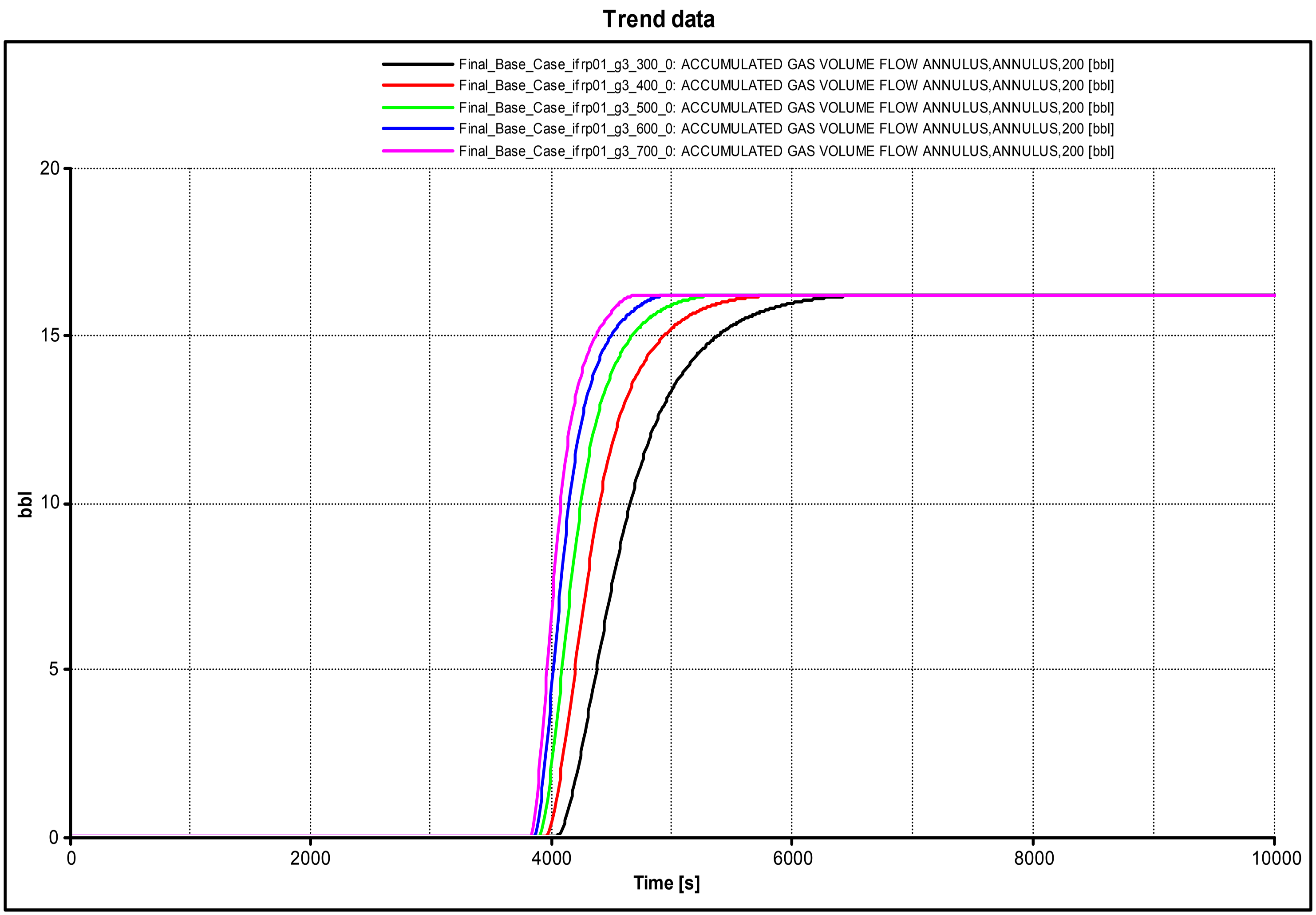

Fig. 43—Accumulated gas out at outlet of annulus, Geometry 3, inclination 0°, circulation rate 300, 400, 500, 600 & 700 GPM.

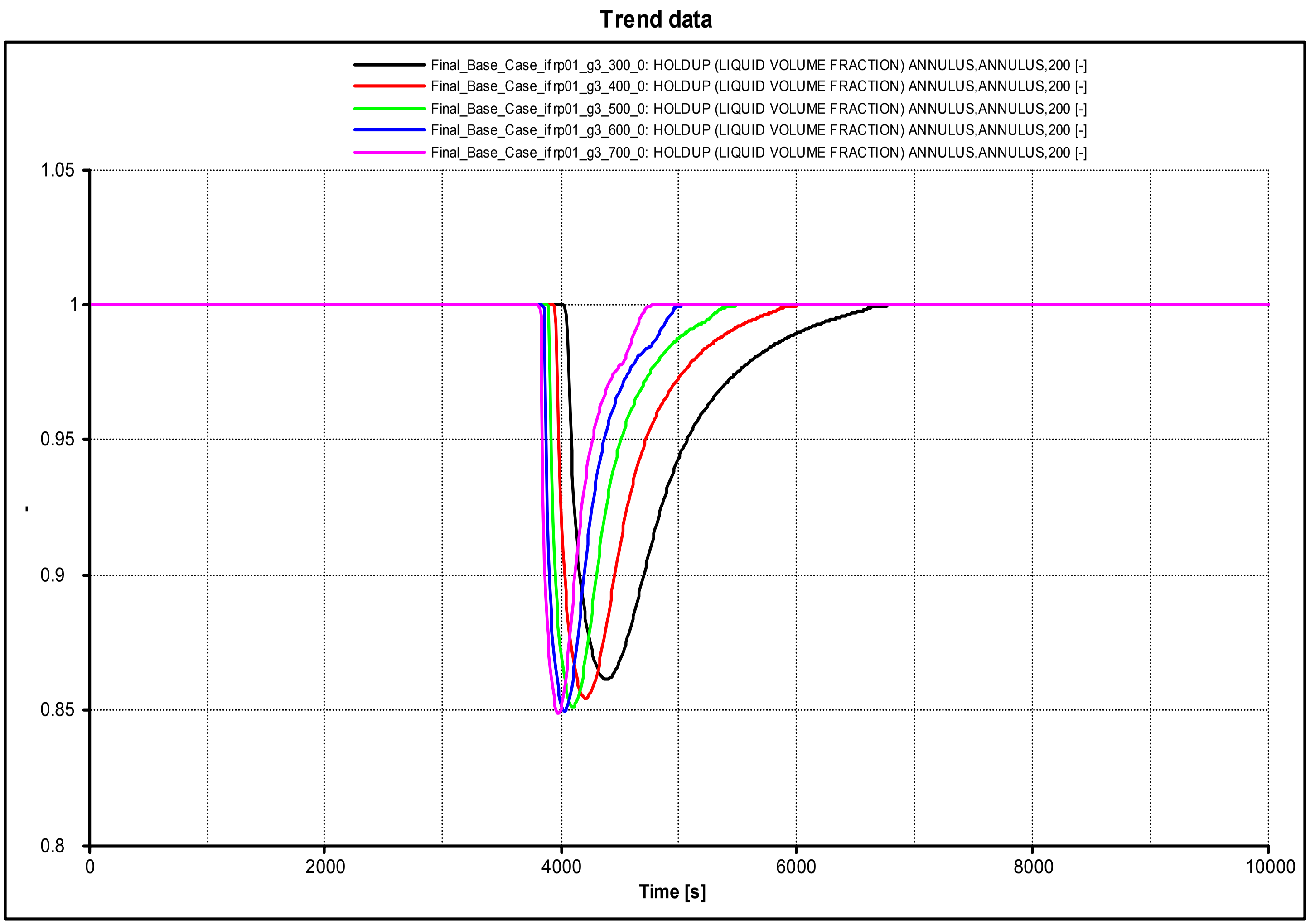

Fig. 44—Liquid holdup at outlet of annulus, Geometry 3, inclination 0°, circulation rate 300, 400, 500, 600, & 700 GPM.

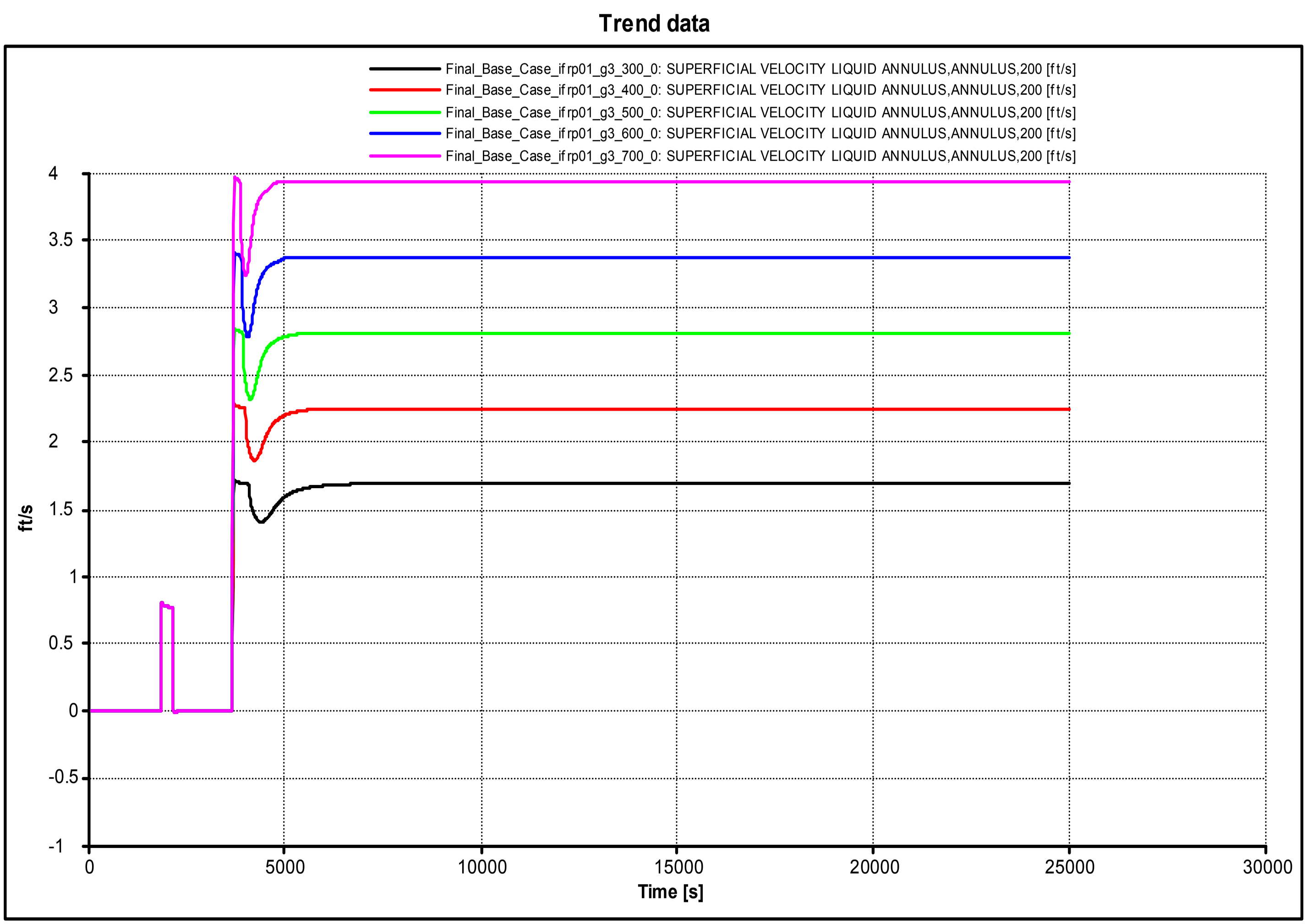

Fig. 45—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 0°, circulation rate 300, 400, 500, 600, & 700 GPM.

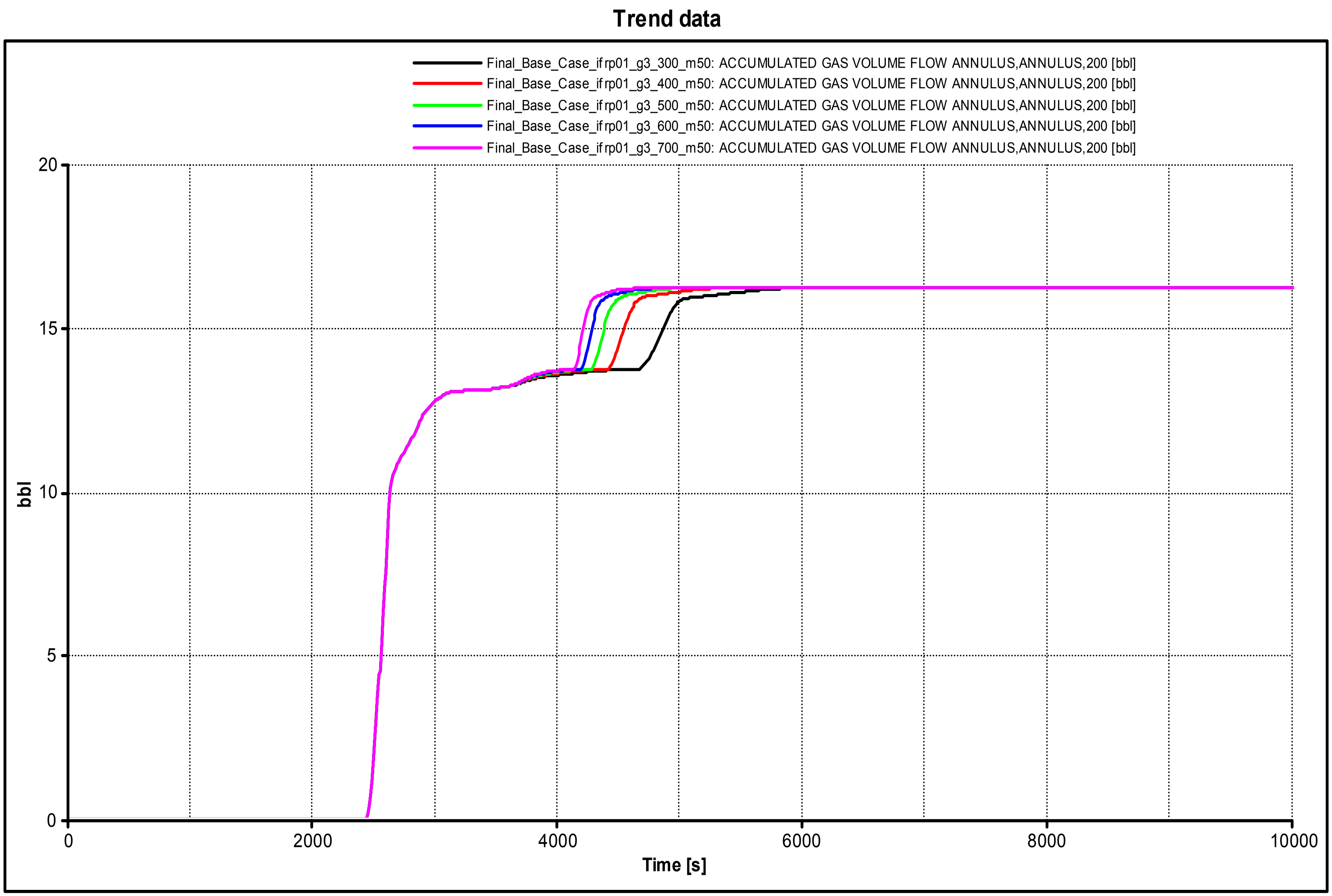

Fig. 46—Accumulated gas out at outlet of annulus, Geometry 3, inclination -5°, circulation rate 300, 400, 500, 600 & 700 GPM.

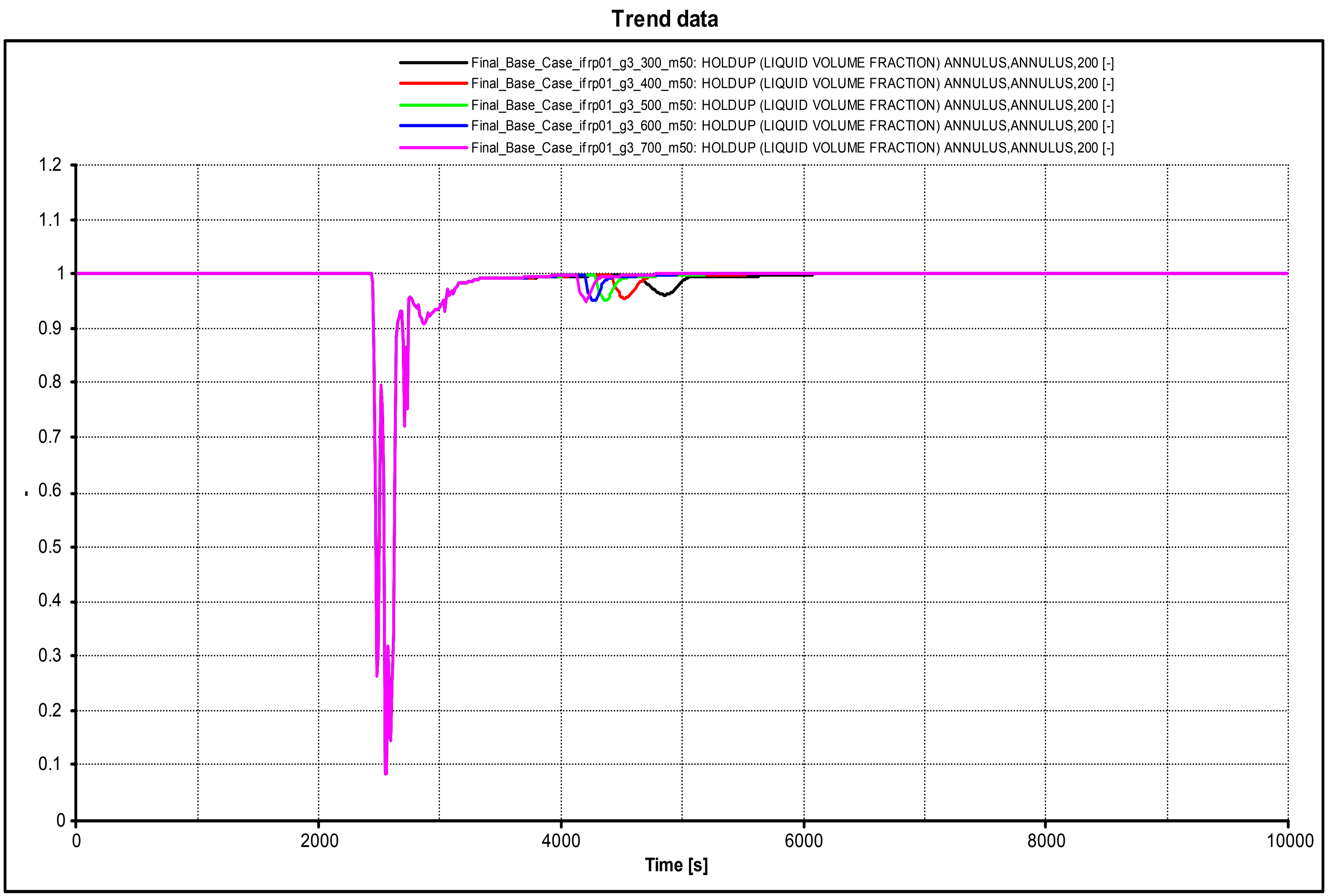

Fig. 47—Liquid holdup at outlet of annulus, Geometry 3, inclination -5°, circulation rate 300, 400, 500, 600, & 700 GPM.

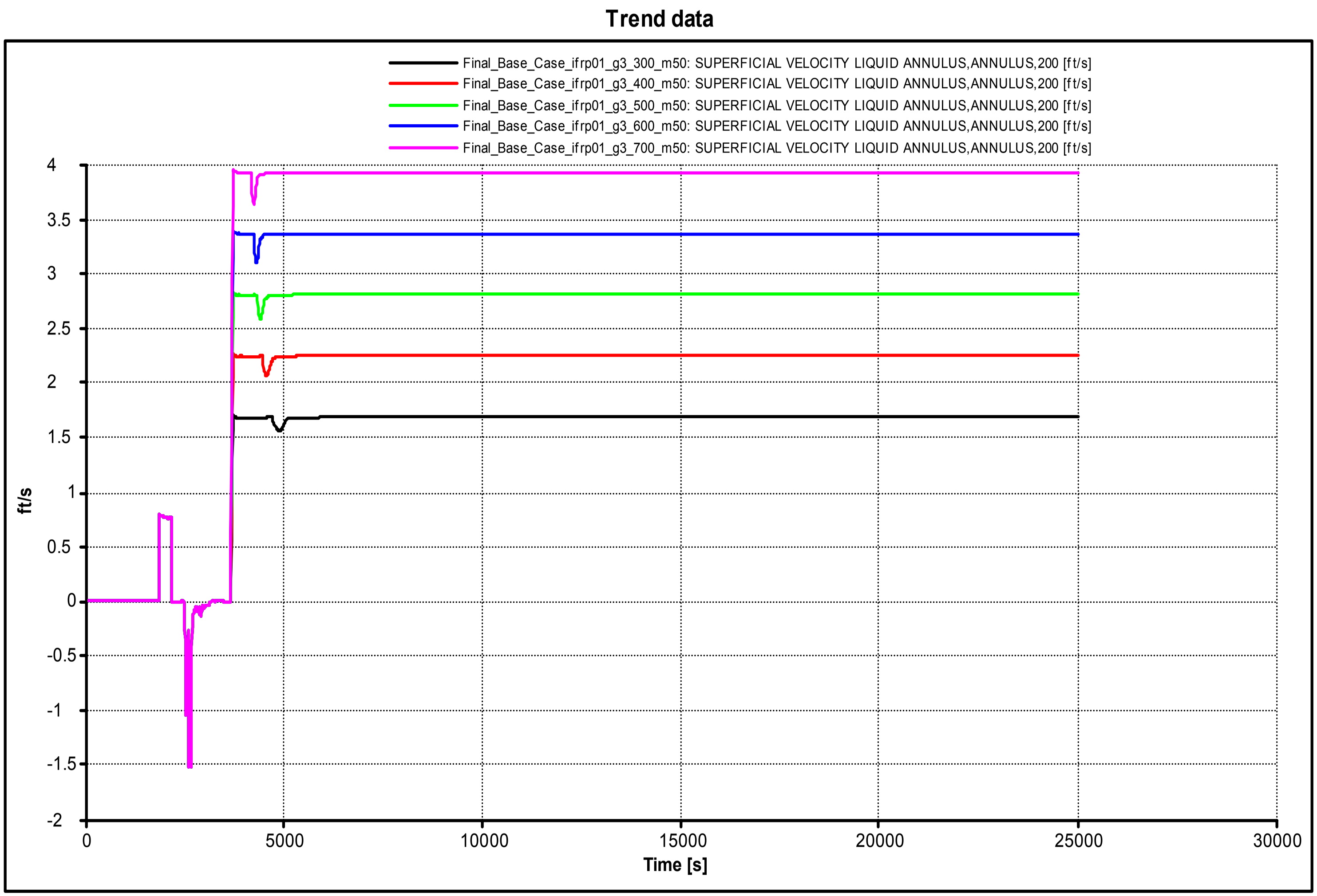

Fig. 48—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination -5°, circulation rate 300, 400, 500, 600, & 700 GPM.

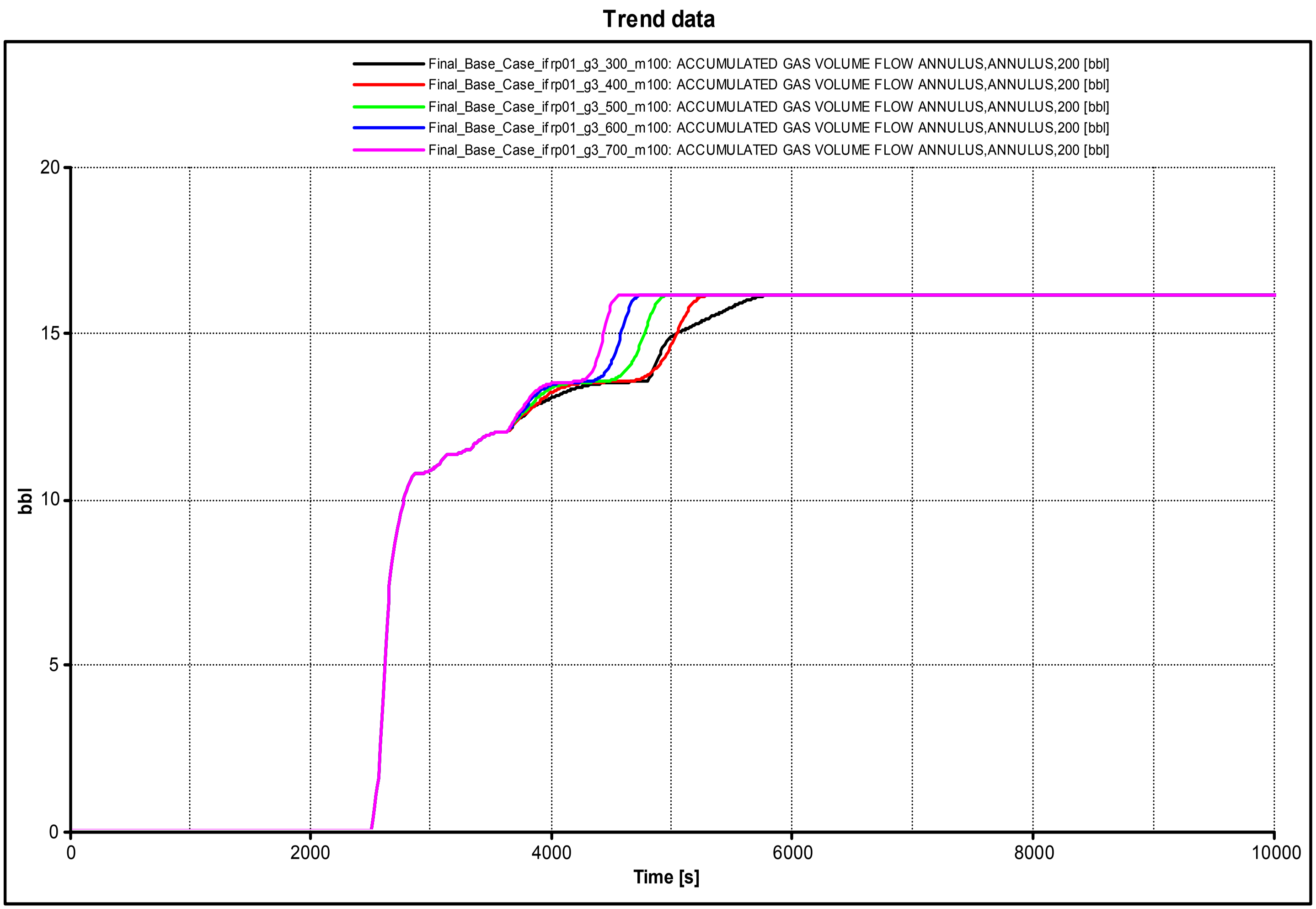

Fig. 49—Accumulated gas out at outlet of annulus, Geometry 3, inclination -10°, circulation rate 300, 400, 500, 600 & 700 GPM.

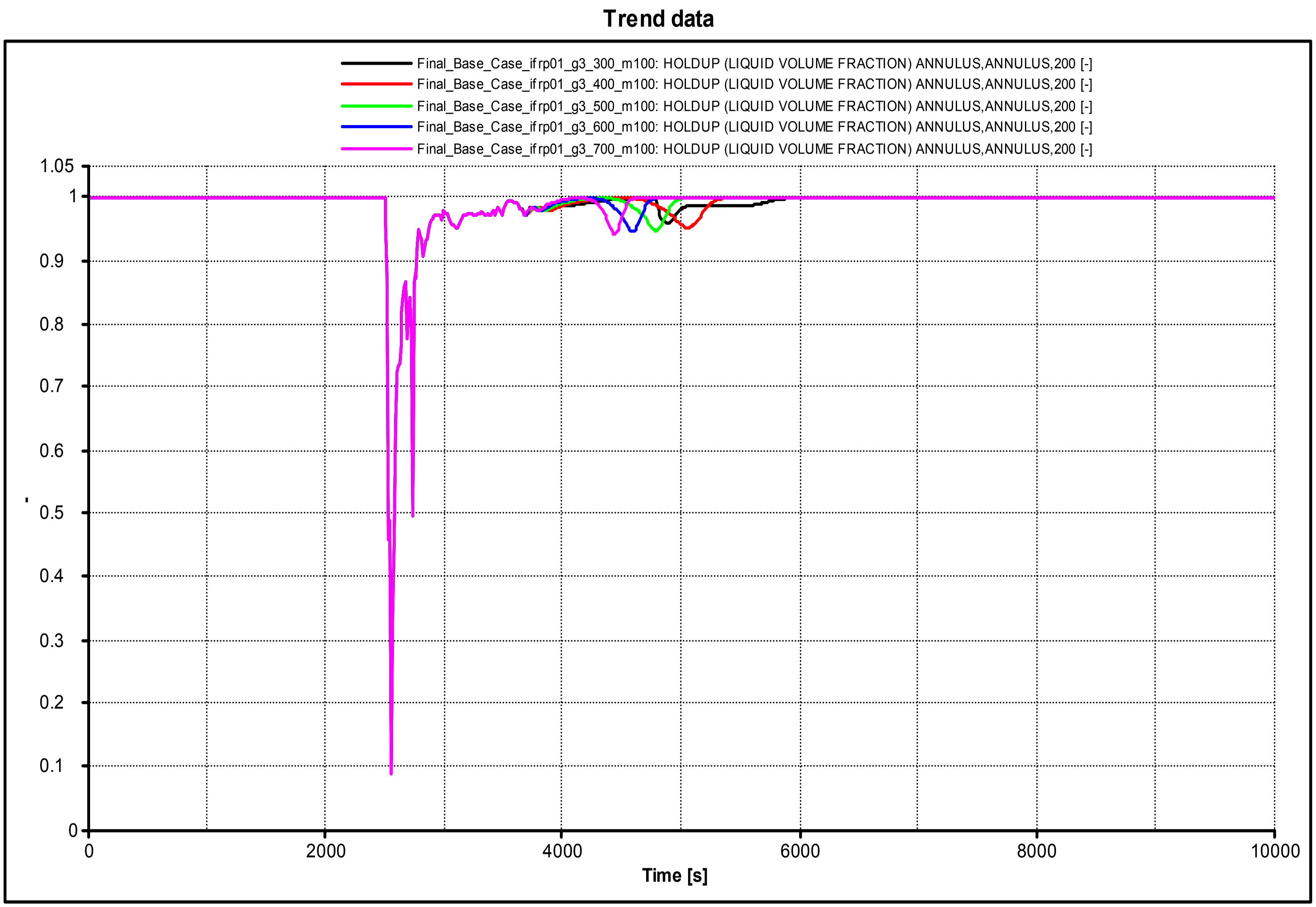

Fig. 50—Liquid holdup at outlet of annulus, Geometry 3, inclination -10°, circulation rate 300, 400, 500, 600, & 700 GPM.

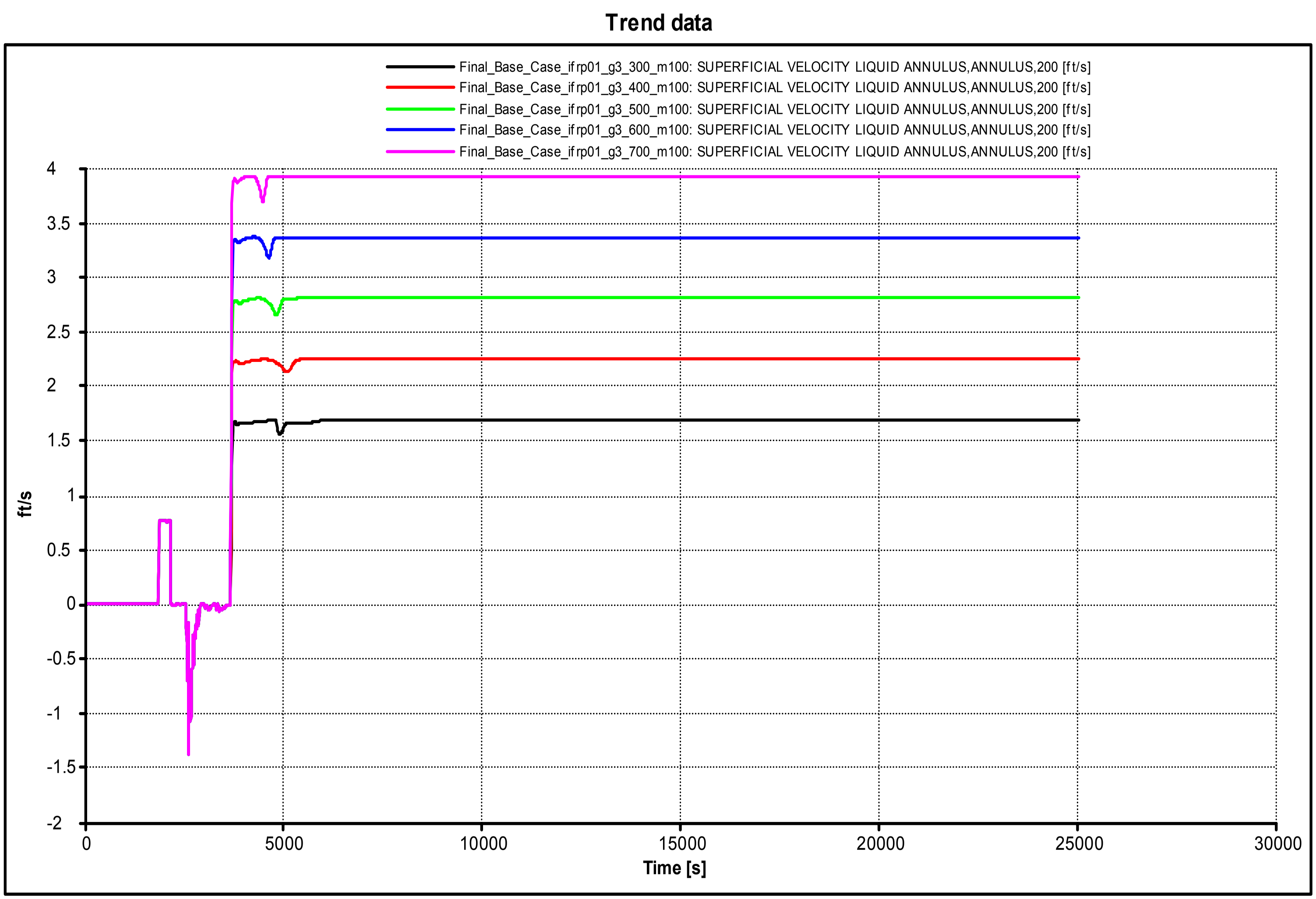

Fig. 51—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination -10°, circulation rate 300, 400, 500, 600, & 700 GPM.

Liquid-Holdup and Flow-Regime-Indication Profiles

Figs. 52 to 60 illustrate liquid holdup and flow regime for a given circulation rate, geometry, and inclination. The following numeric values correspond to the flow regimes: Stratified Flow = 1, Annular Flow = 2, Slug Flow = 3, and Bubble Flow = 4. For inclinations greater than horizontal, several flow regimes are present. Bubble flow is observed in front of the migrating gas kick. Slug flow or stratified flow is present in the portion of the wellbore where the majority of the gas is present, and a stratified flow regime exists behind the gas influx. Figs. 52, 55, and 58 represent these data. For horizontal cases, a stratified flow regime is present throughout the removal of the gas influx. Figs. 53, 56, and 59 represent these data. For inclinations below horizontal, slug flow or stratified flow may be present in the portion of the wellbore the majority of the gas occupies. A region of bubble flow follows this until stratified flow is reached. Figs. 54, 57, and 60 represent these data.

Wellbore Friction

Fig. 61 illustrates the simulation study varying annular friction. As the relative roughness value increased, the kick removal process became more efficient.

Runs Performed With Various Mud Properties

Effects of Mud Properties

Figs. 62 to 66 depict the results of runs with varying mud properties. These runs were simulated using Geometry 2 with an inclination of 10° at a circulation rate of 275 GPM. Fig. 62 illustrates the effect of viscosity on kick removal. It shows that a fluid with a higher effective viscosity is more efficient at transporting the kick. All of the fluids are significantly better than water. Fig. 64 illustrates the effect of density coupled with viscosity. The variance in accumulated gas out reflect slight differences in outlet pressure resulting from the hydrostatic head of the muds. Fig. 66 compares the effects of mud density and mud viscosity. The weighted muds are slightly more efficient at removing the kick from the wellbore. However, viscosity is the overruling parameter.

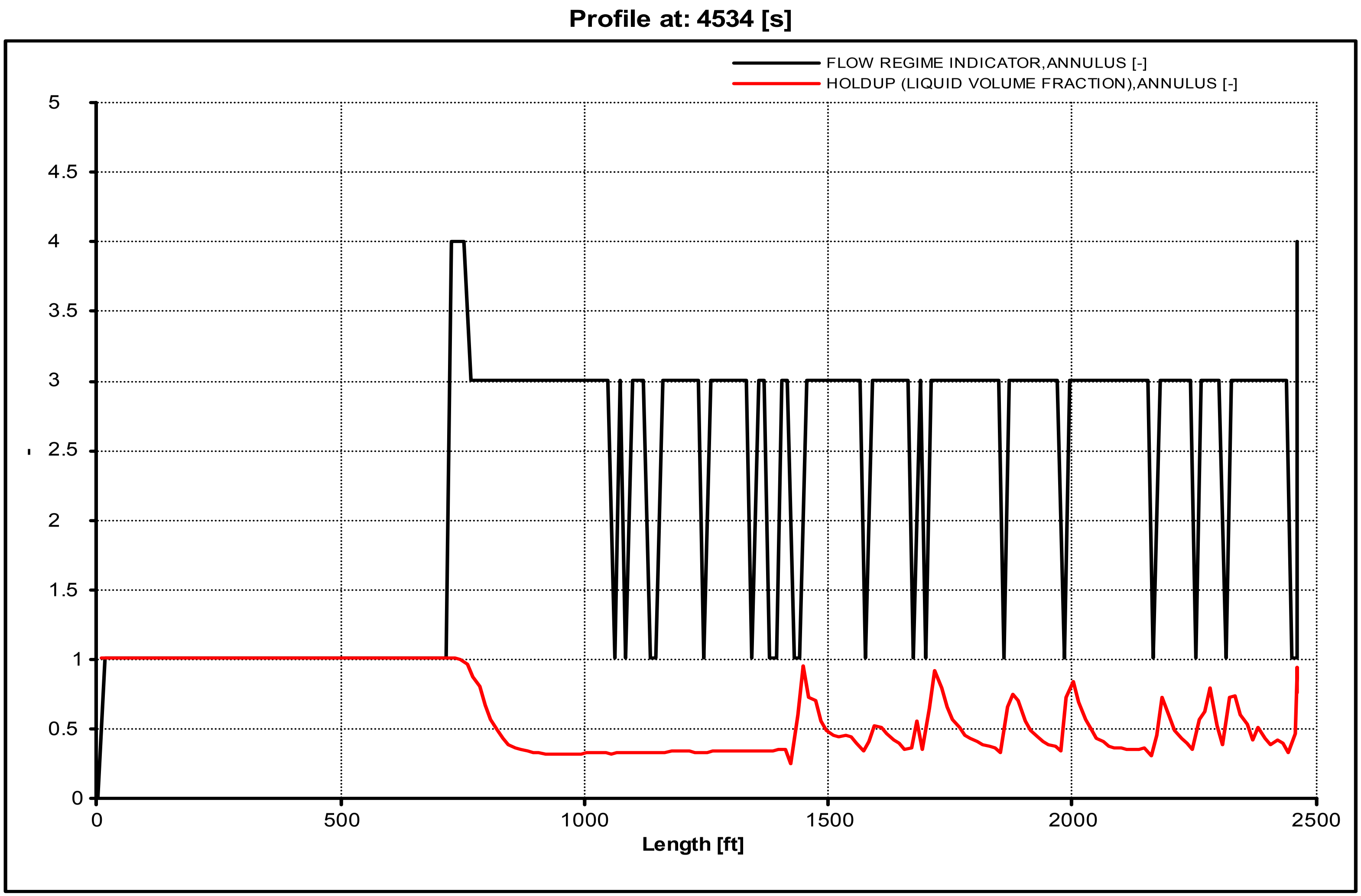

Fig. 52—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 10°, circulation rate 100 GPM.

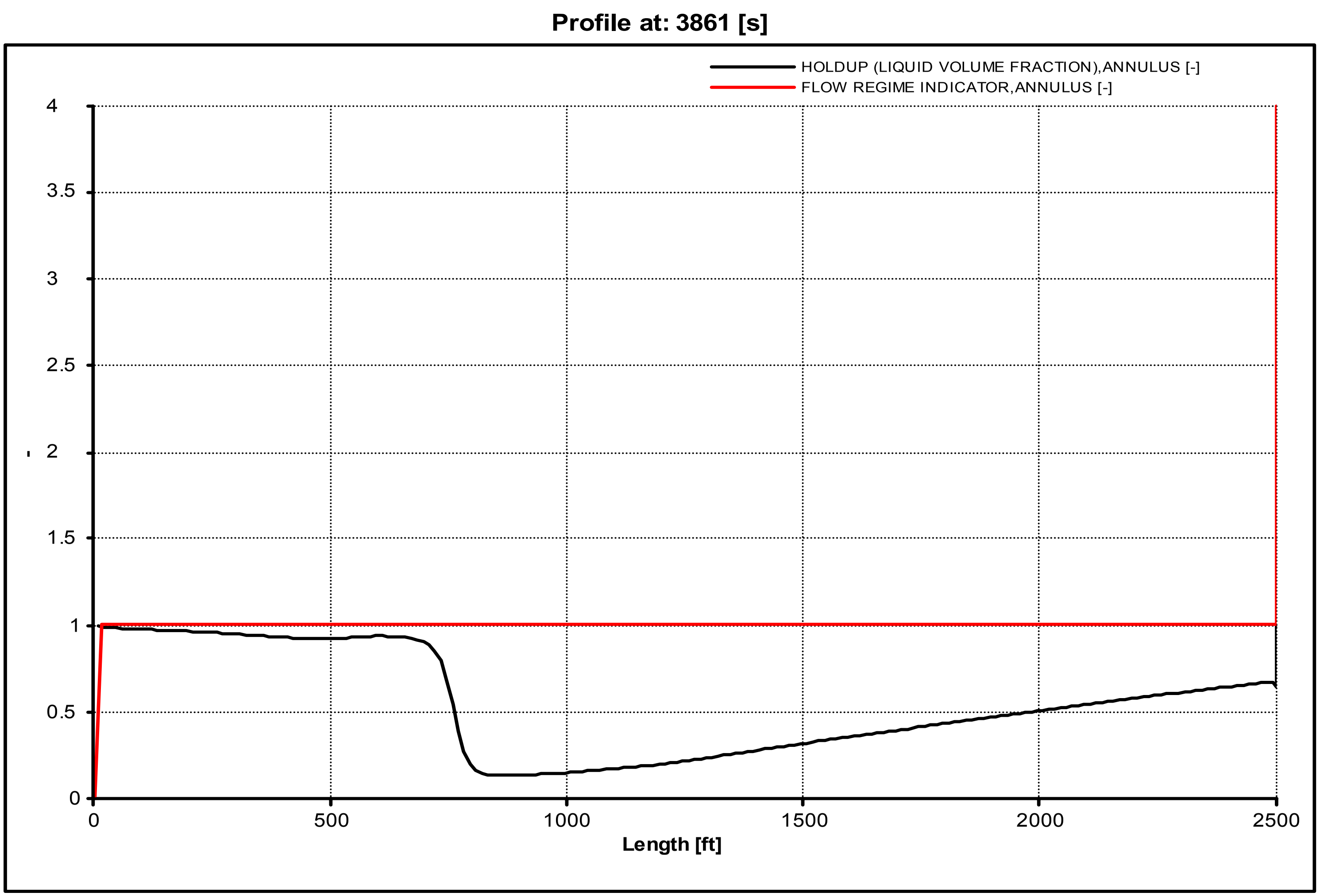

Fig. 53—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 0°, circulation rate 100 GPM.

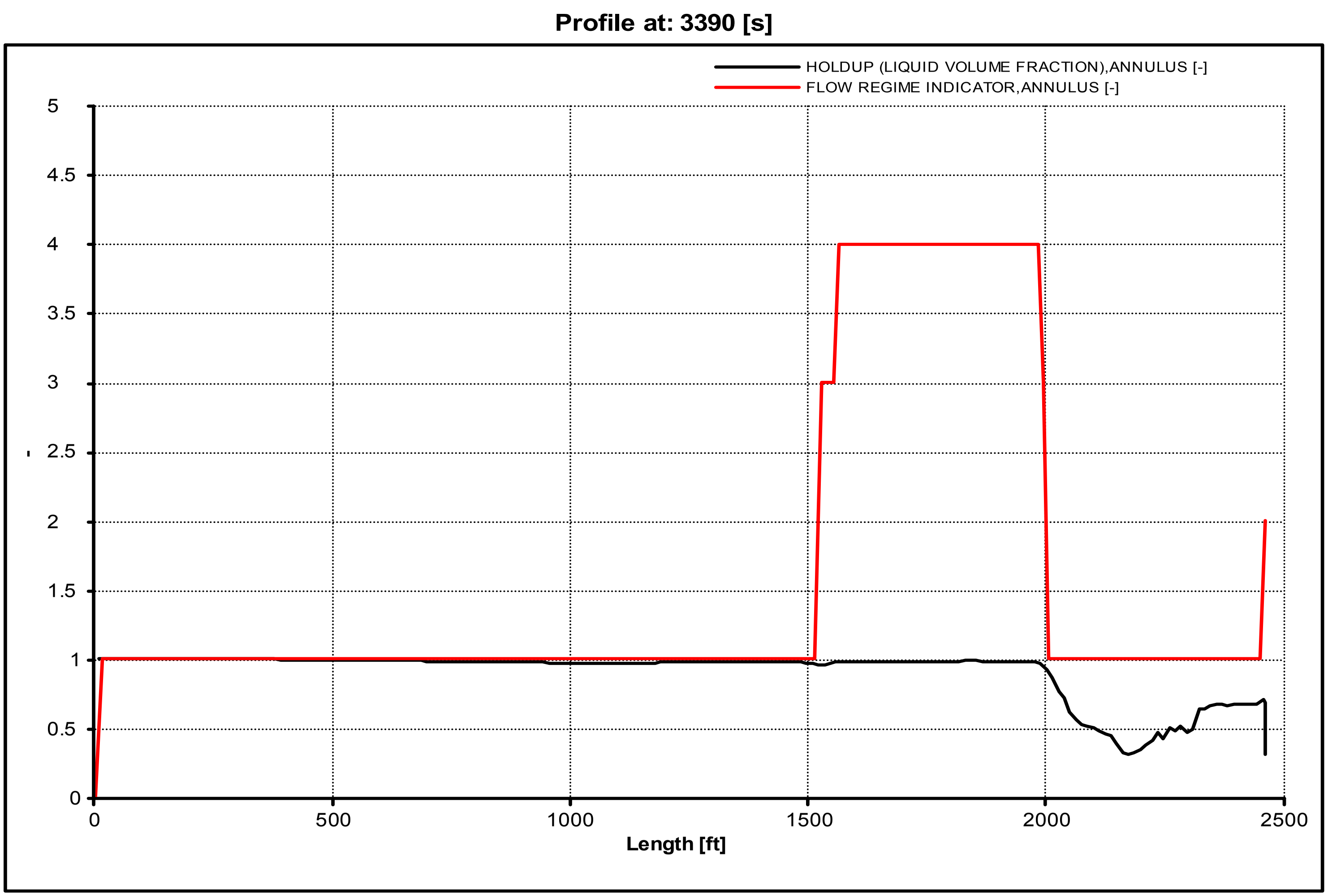

Fig. 54—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination -10°, circulation rate 100 GPM.

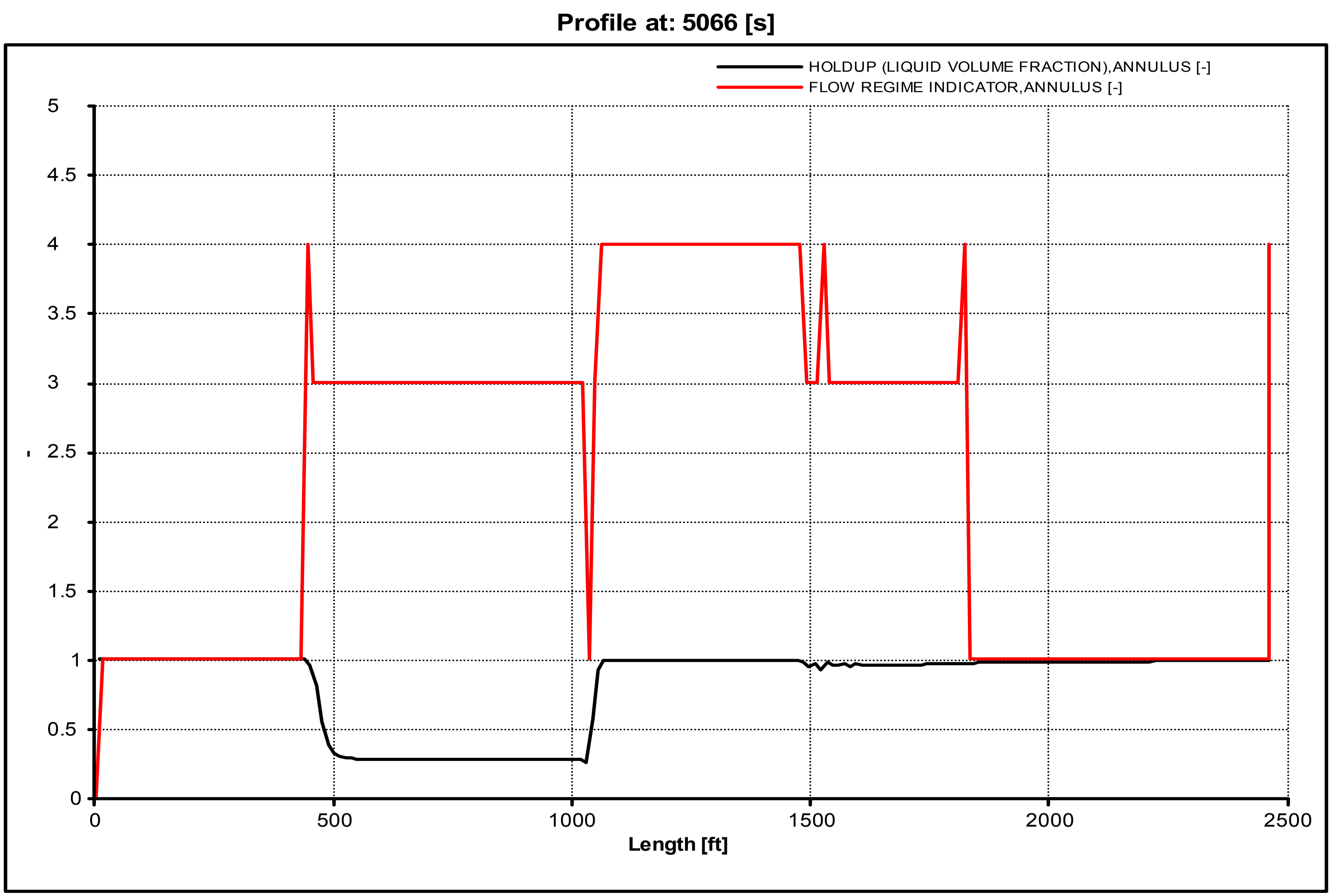

Fig. 55—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

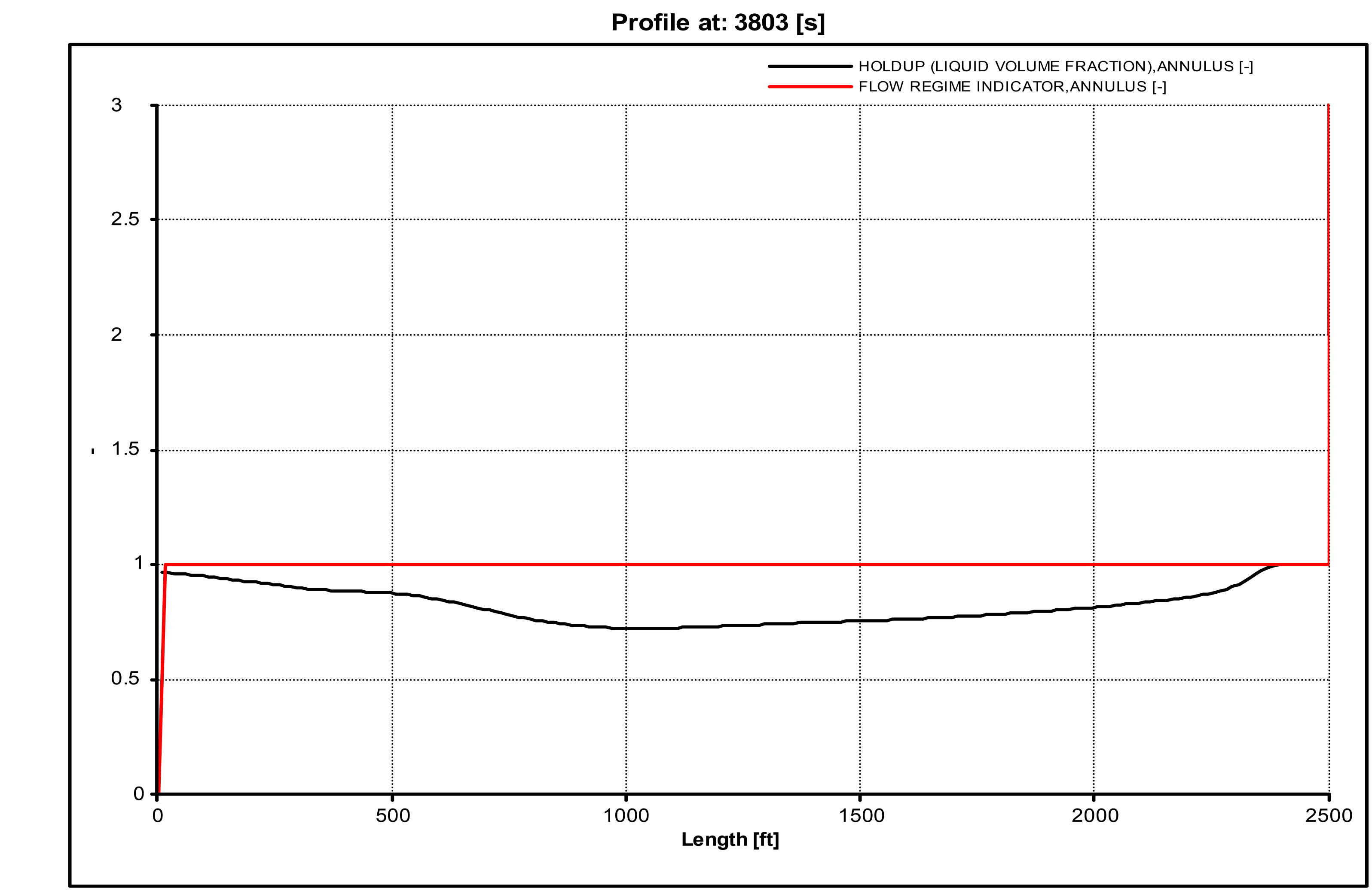

Fig. 56—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 0°, circulation rate 275 GPM.

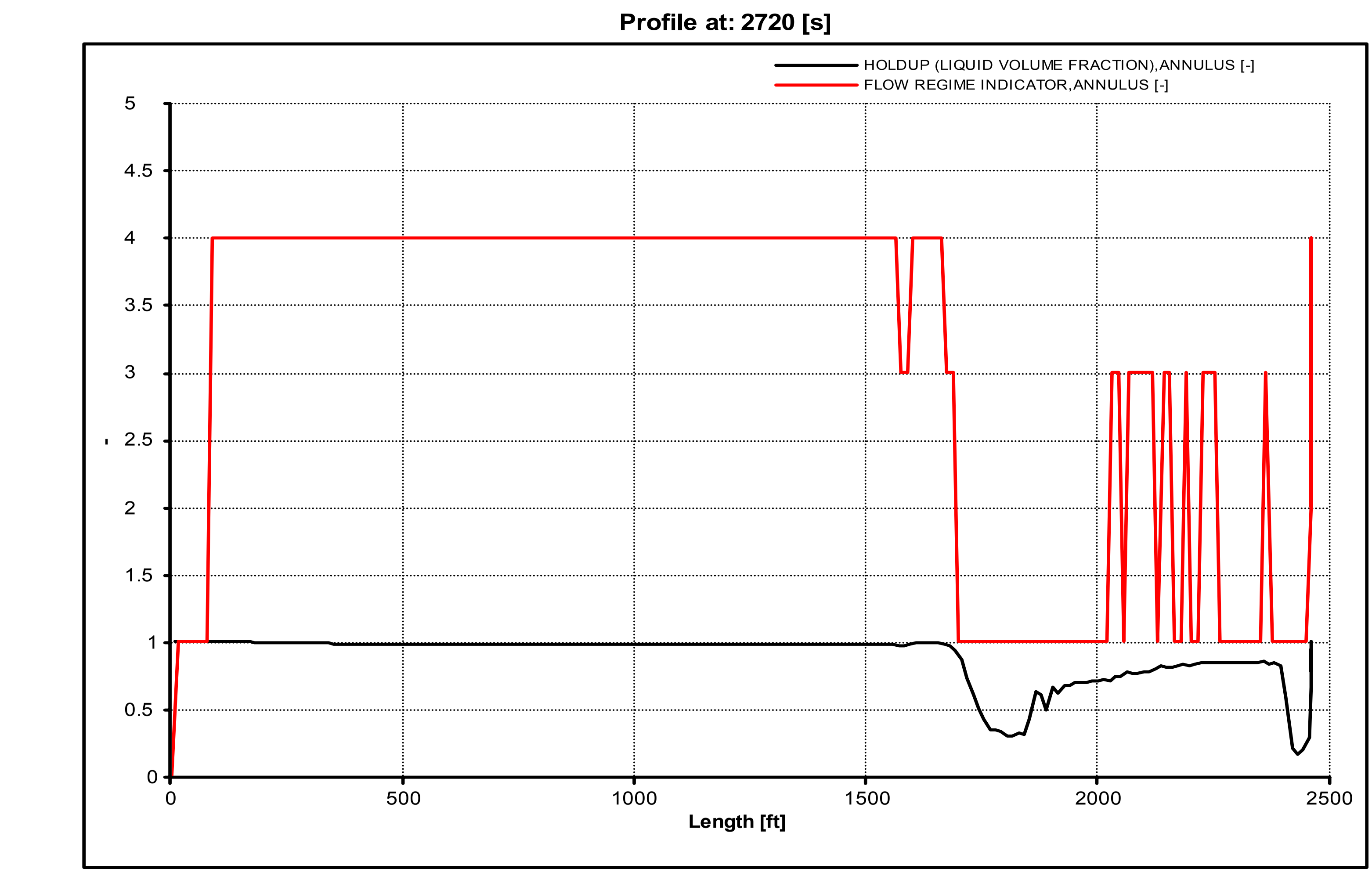

Fig. 57—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination -10°, circulation rate 275 GPM.

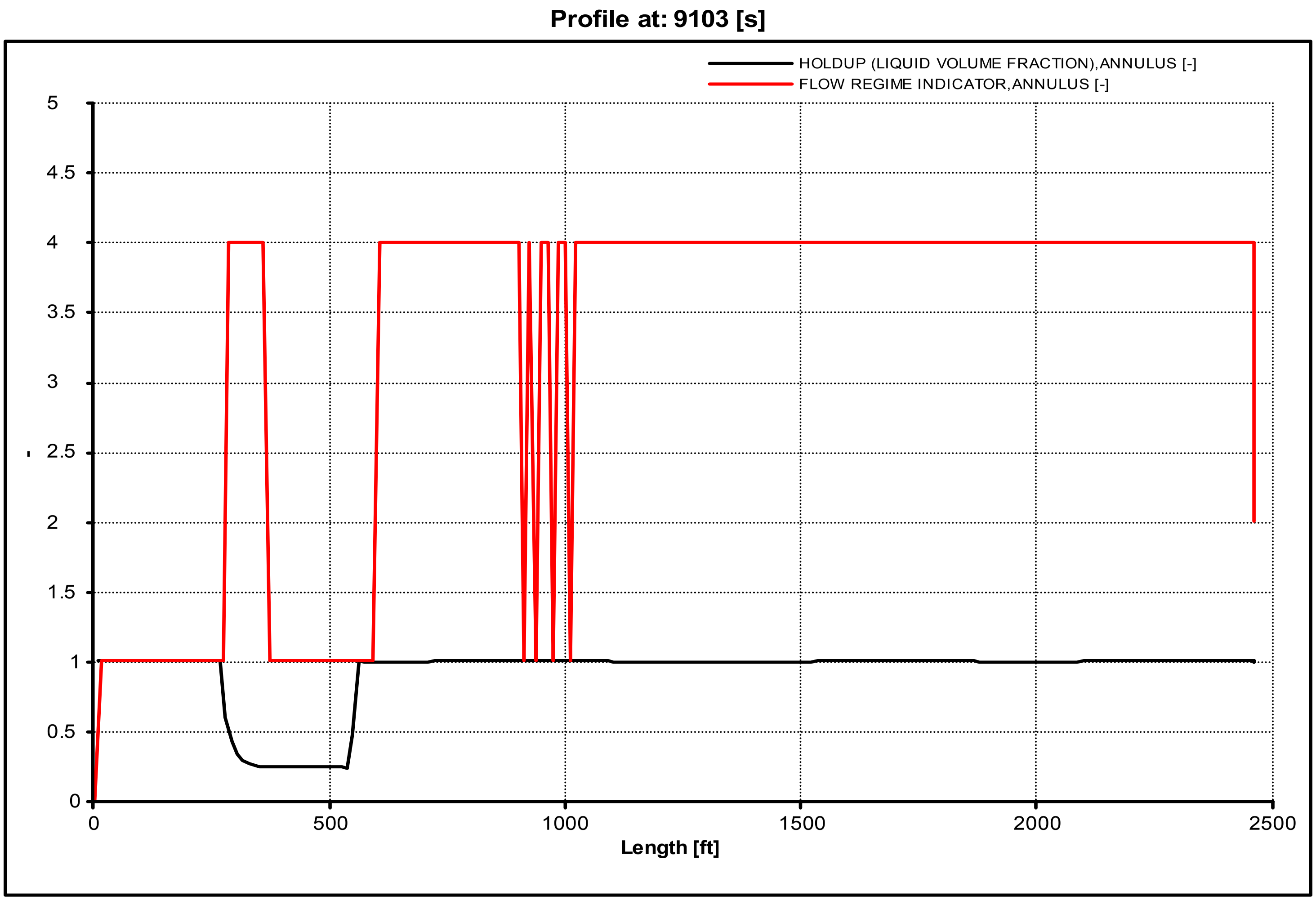

Fig. 58—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 10°, circulation rate 500 GPM.

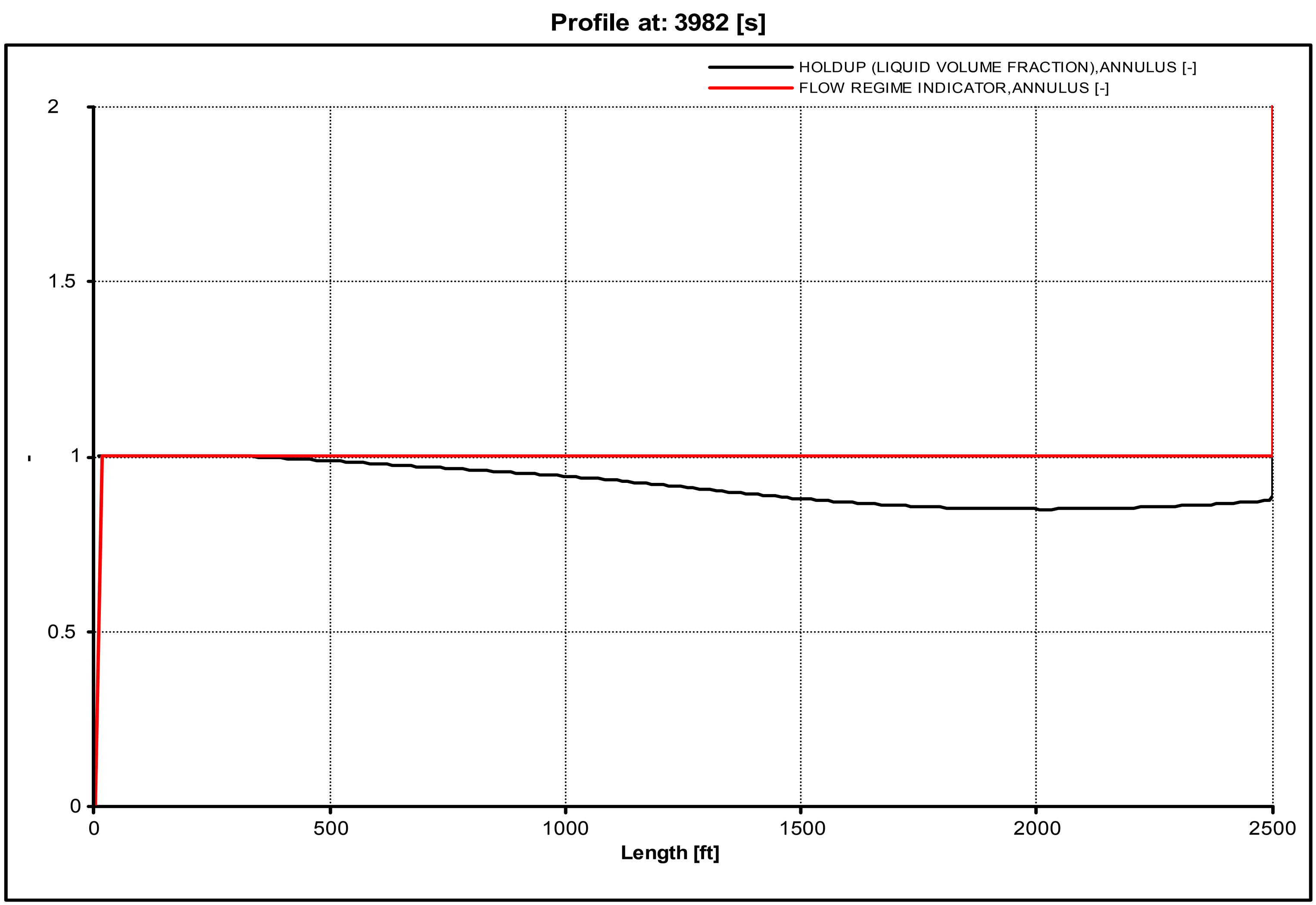

Fig. 59—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 0°, circulation rate 500 GPM.

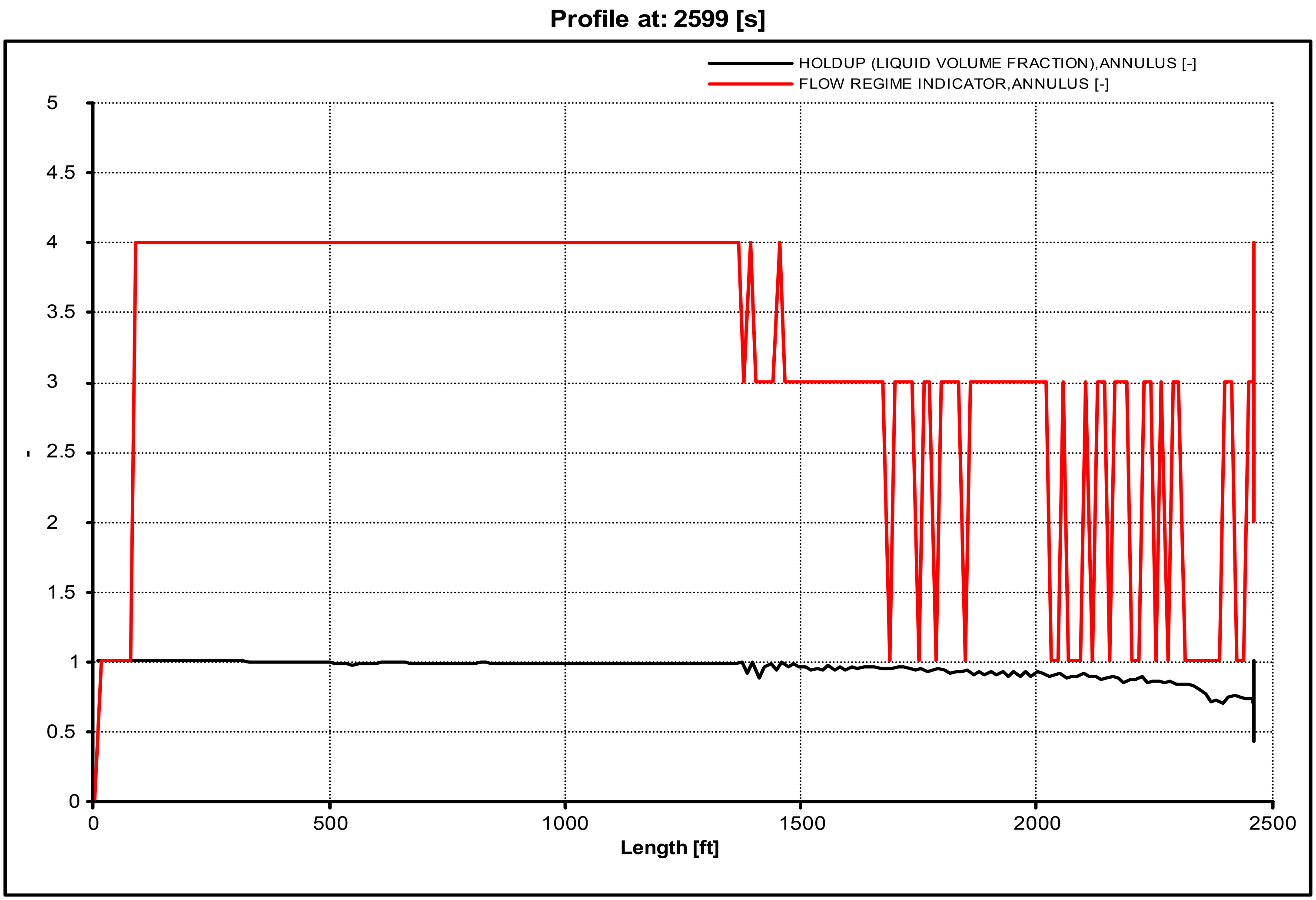

Fig. 60—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination -10°, circulation rate 500 GPM.

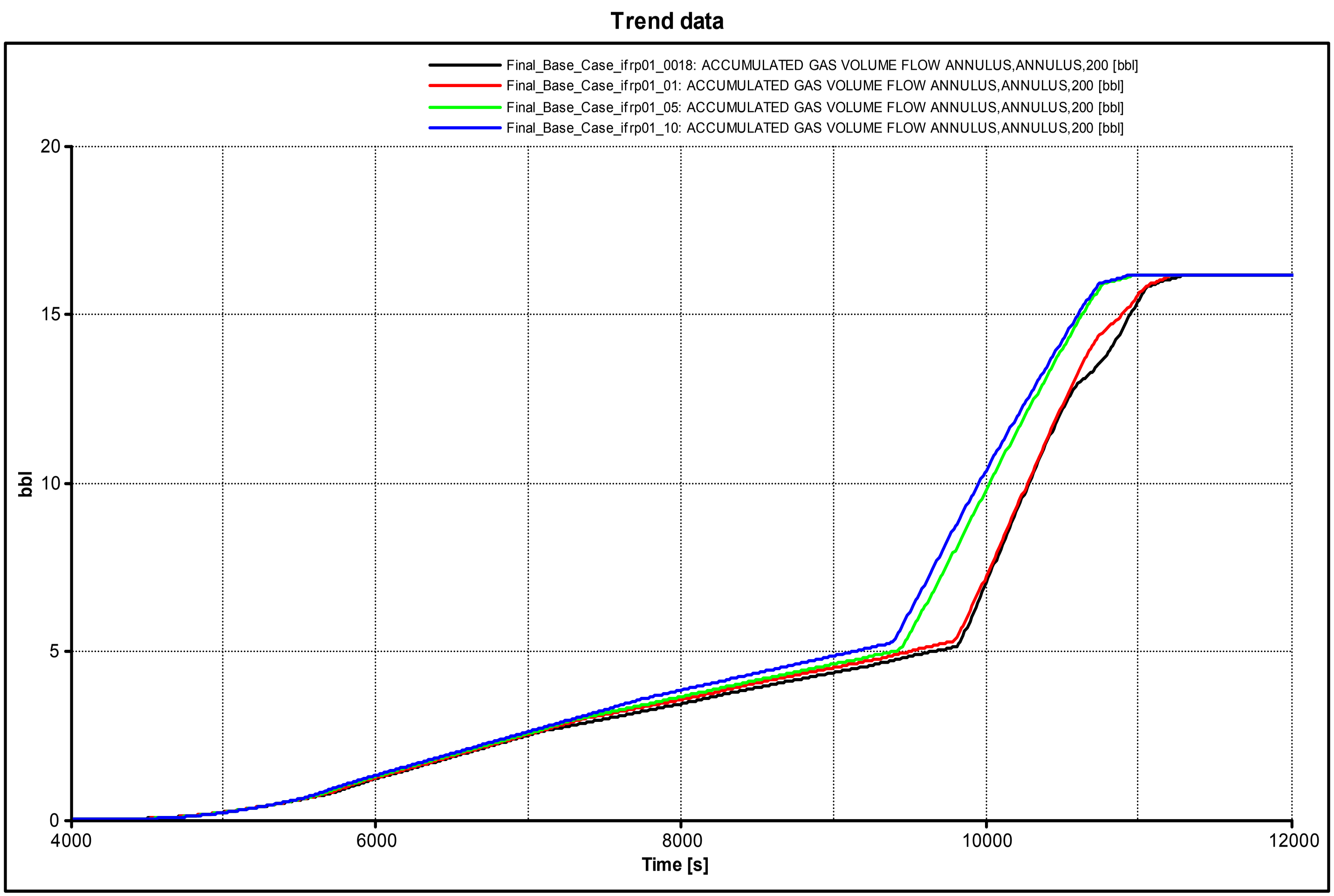

Fig. 61—Friction profile plot, Geometry 2, inclination 10°, circulation rate 275 GPM, relative roughness 0.0018, 0.01, 0.05, & 0.10.

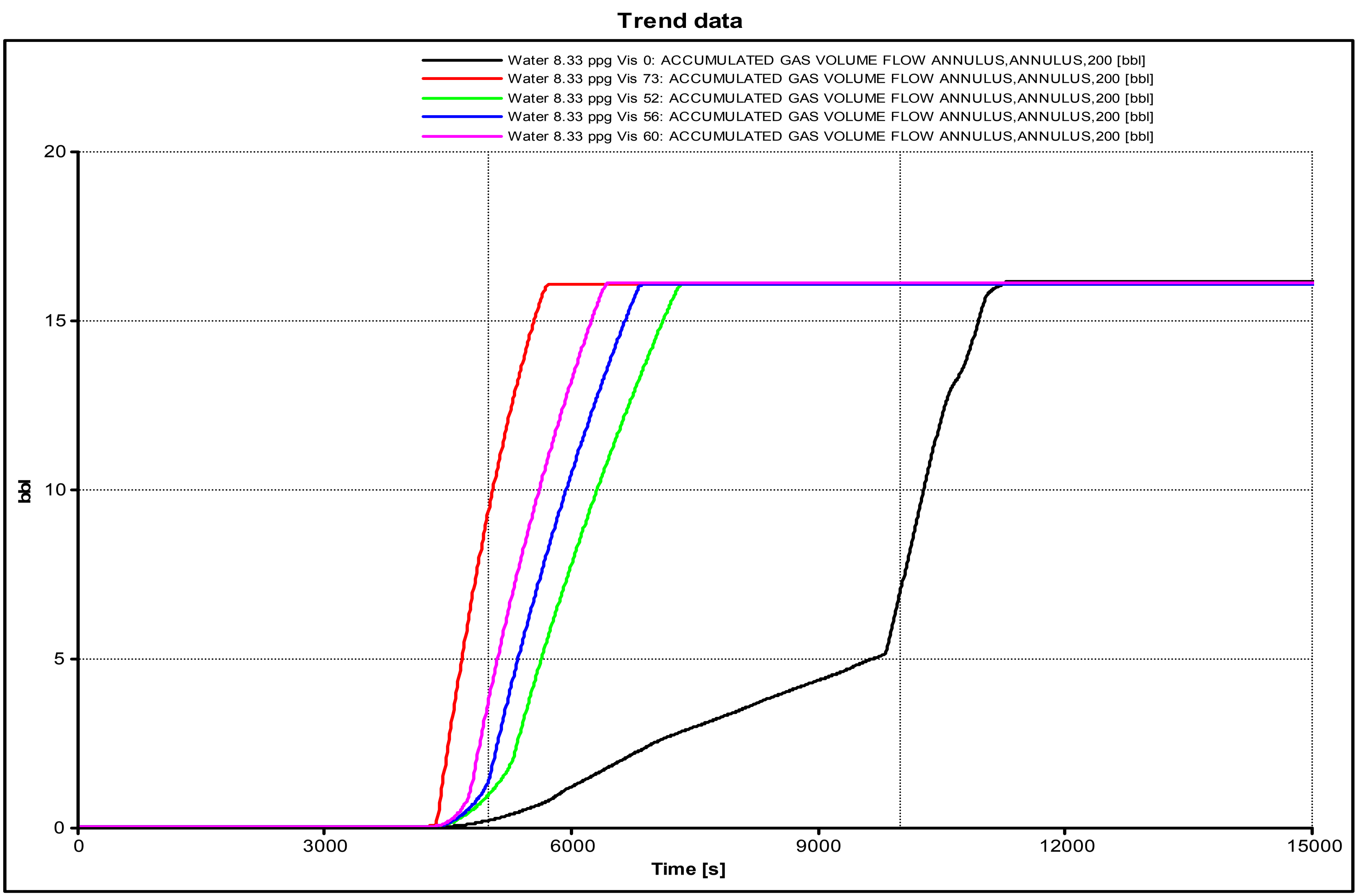

Fig. 62—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

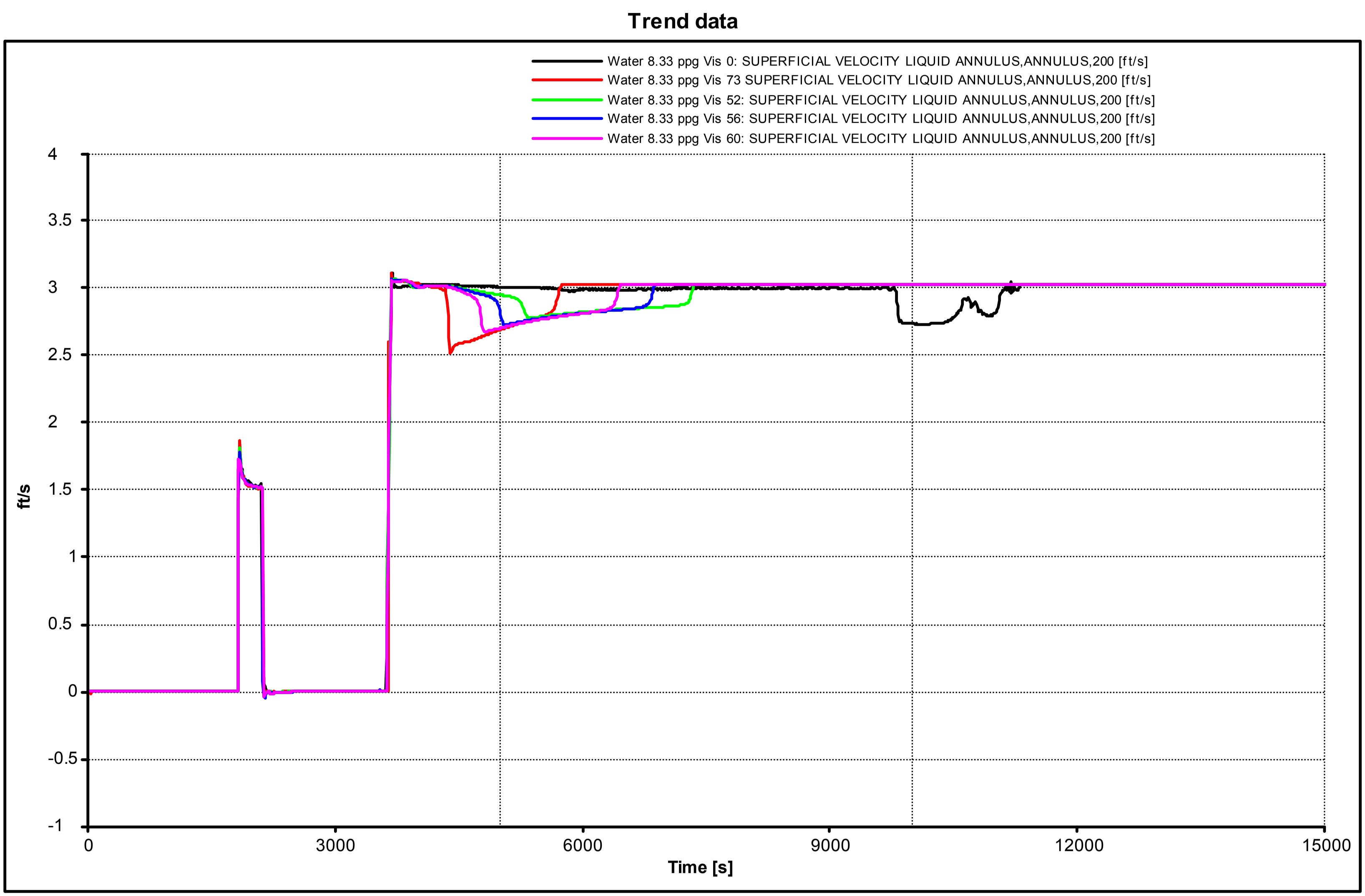

Fig. 63—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

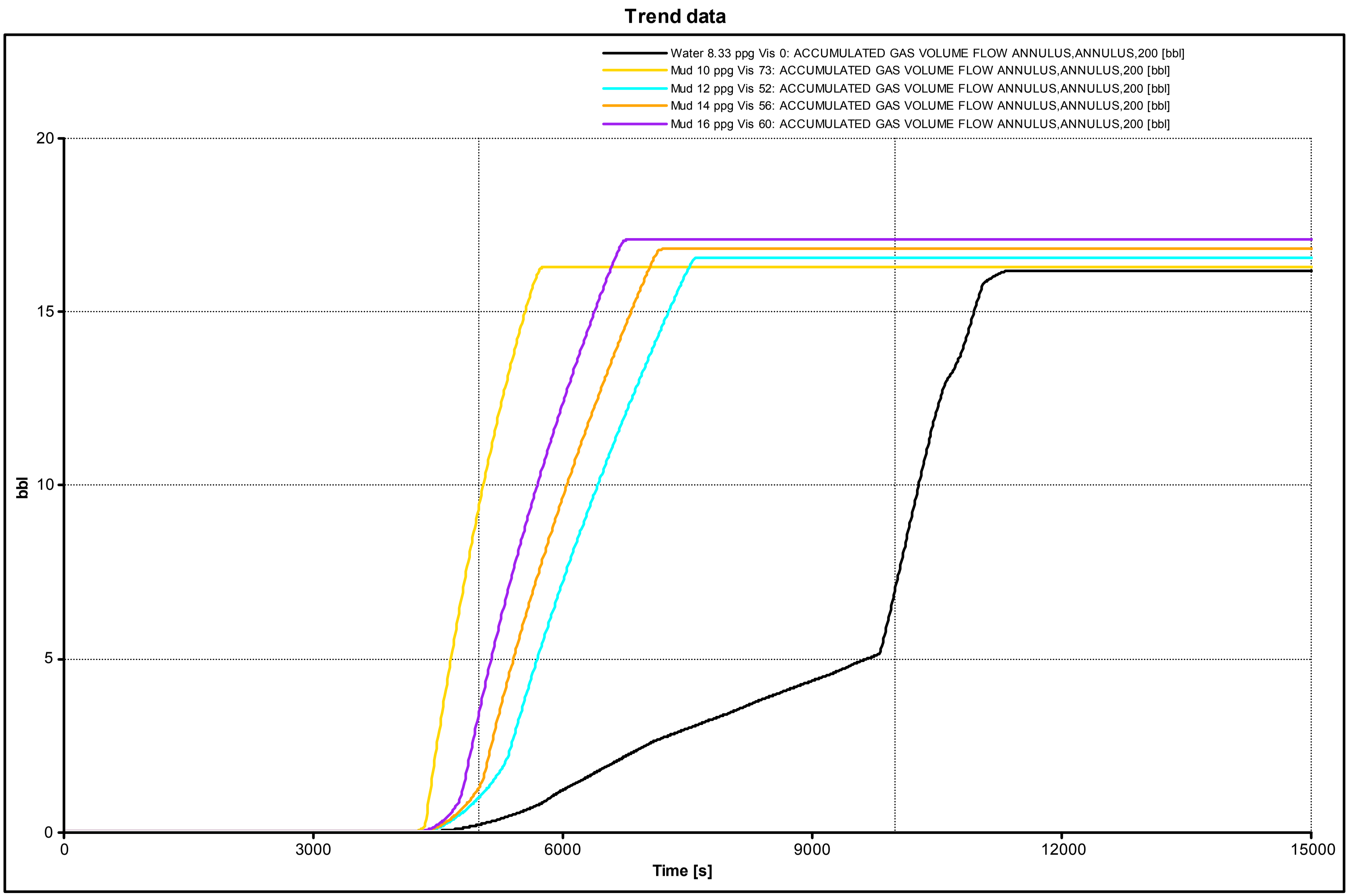

Fig. 64—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

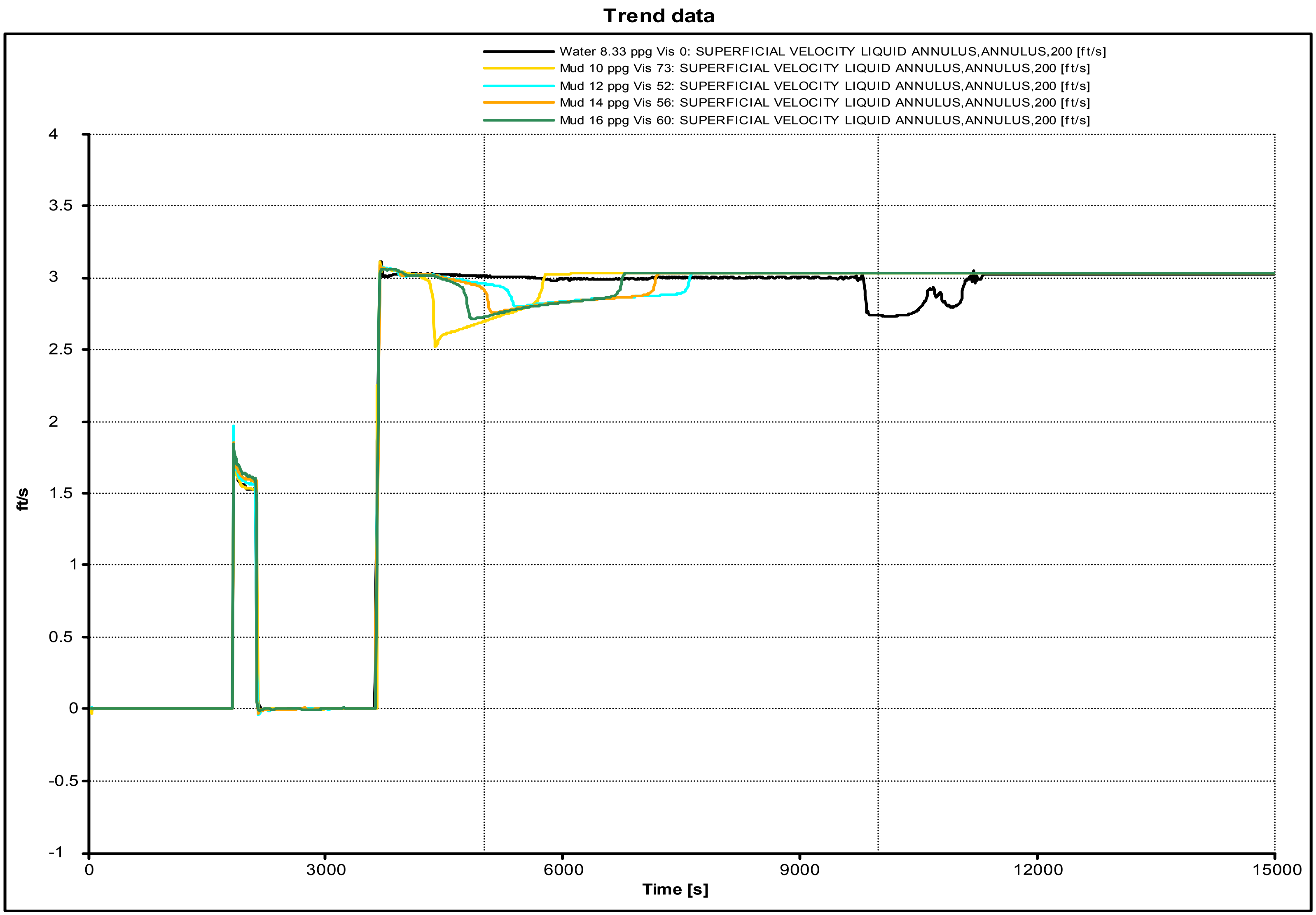

Fig. 65—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

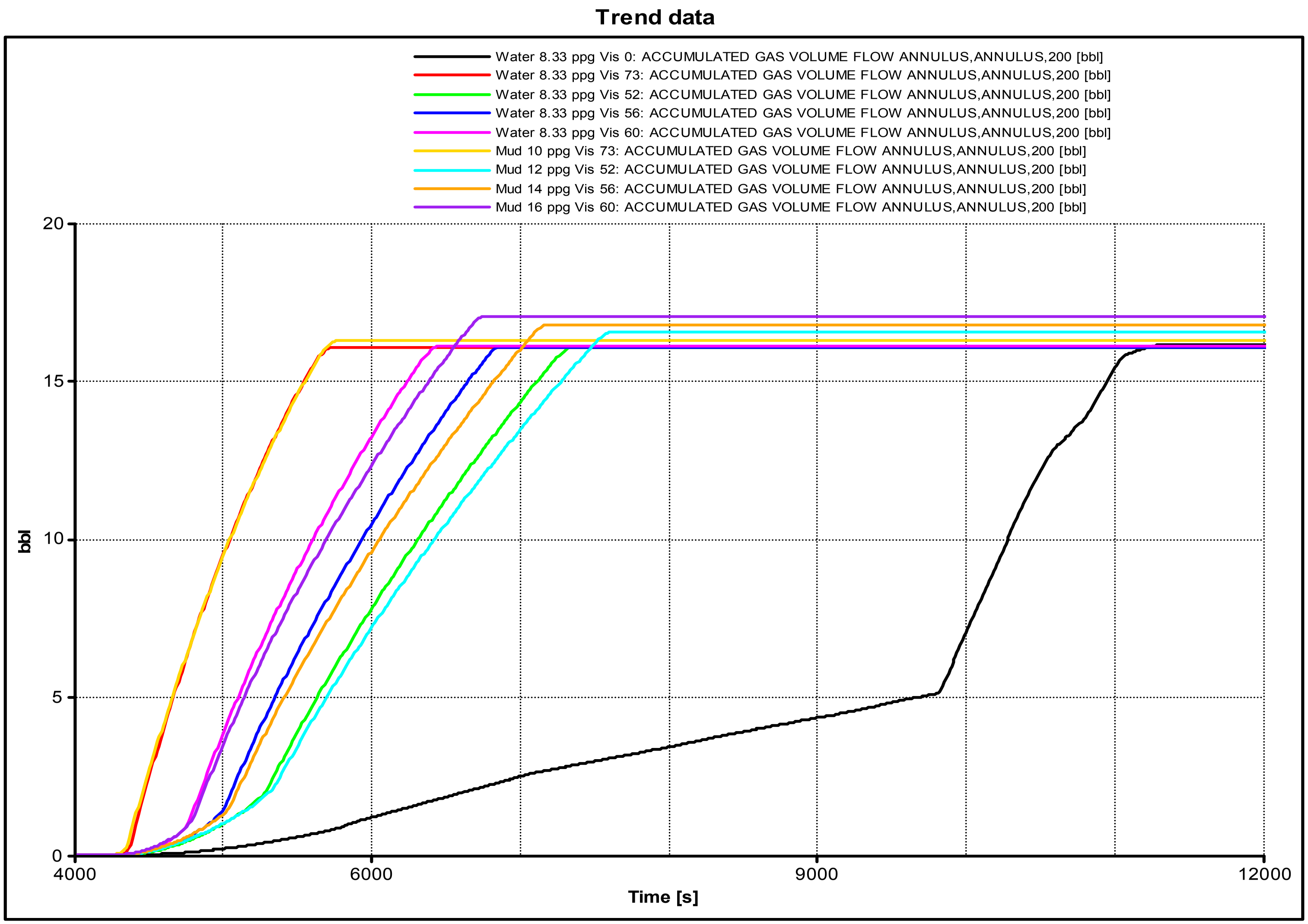

Fig. 66—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 275 GPM.

Geometry 1

Figs. 67-70 represent data for simulation runs performed using a 14-ppg mud with *n* and *K* values of 0.773 and 1.275 respectively. Using the power-law coefficients, OLGA calculates the effective viscosity, which is dependent upon circulation rate. Comparing Figs. 67 and 68 to Figs. 7 and 9, the viscous fluid transports the gas kick more efficiently and at lower annular velocity. A rate of 100 GPM and annular velocity of 3.2 ft/sec were required to remove the kick with water. For the mud, a rate of 60 GPM and annular velocity of 1.9 ft/sec were required to remove the kick. The ability to use a slower circulating kill rate is desirable, as it allows more precise control of the well. Figs. 69 and 70 illustrate the liquid holdup and flow regime for a given time. The flow regime was stratified flow, which is considerably different from the slug-flow regime depicted in Fig. 7 for the water run. The difference in flow regime is attributed to mud properties affecting the transition between laminar and turbulent flow.

Geometry 2

The results in **Figs. 71 to 74** exhibited the same development as for the previous geometry. For the run performed with water, a circulation rate of 275 GPM and annular velocity of 3.1 ft/sec was required to remove the kick. Using the 14-ppg mud, these values were lowered to a circulation rate of 250 GPM and an annular velocity of 2.75 ft/sec. Figs. 73 and 74 show the flow regimes for circulation rates of 200 and 250 GPM. Again, stratified flow is exhibited as opposed to slug flow for the water case.

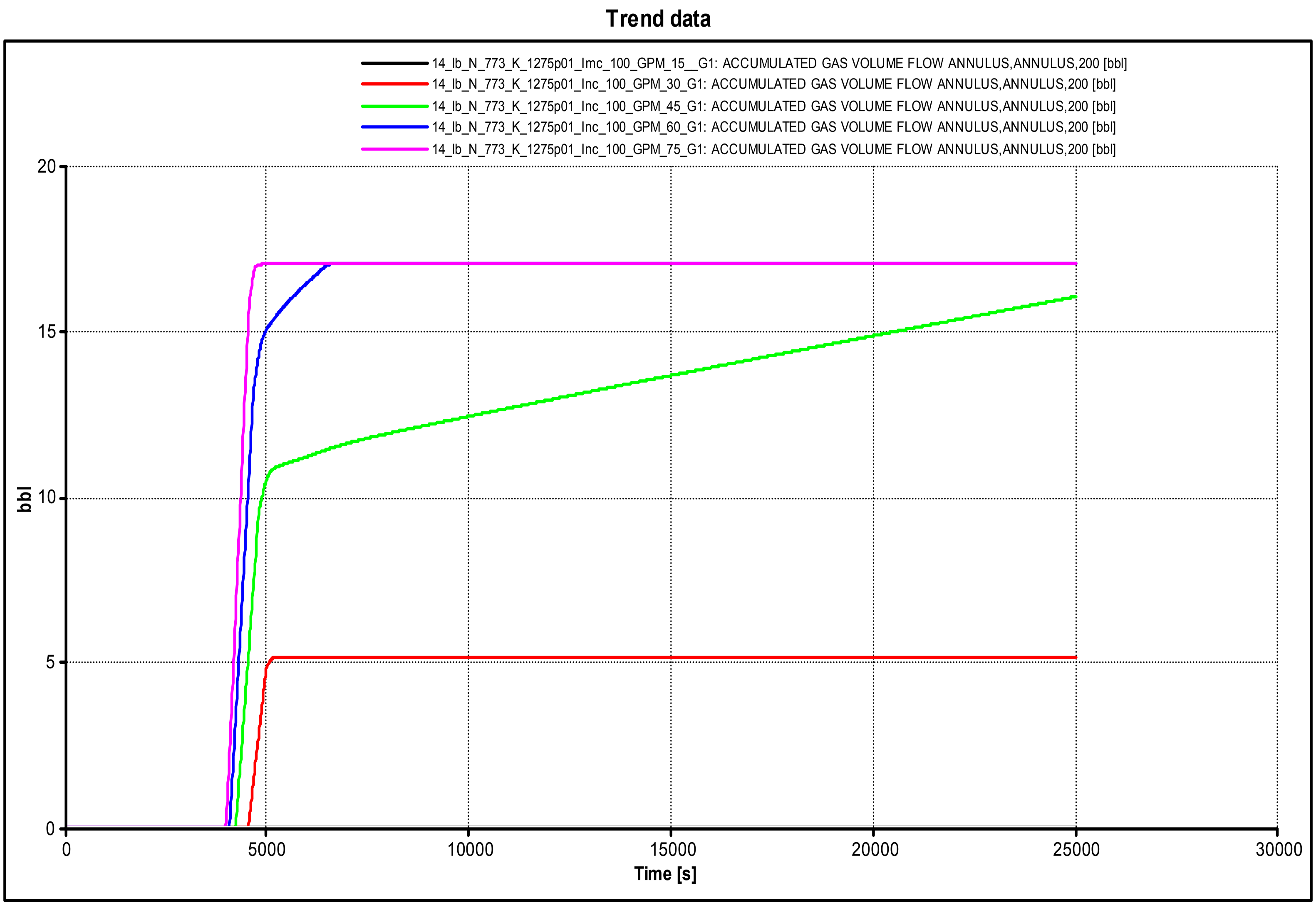

Fig. 67—Accumulated gas out at outlet of annulus, Geometry 1, inclination 10°, circulation rate 15, 30, 45, 60, & 75 GPM.

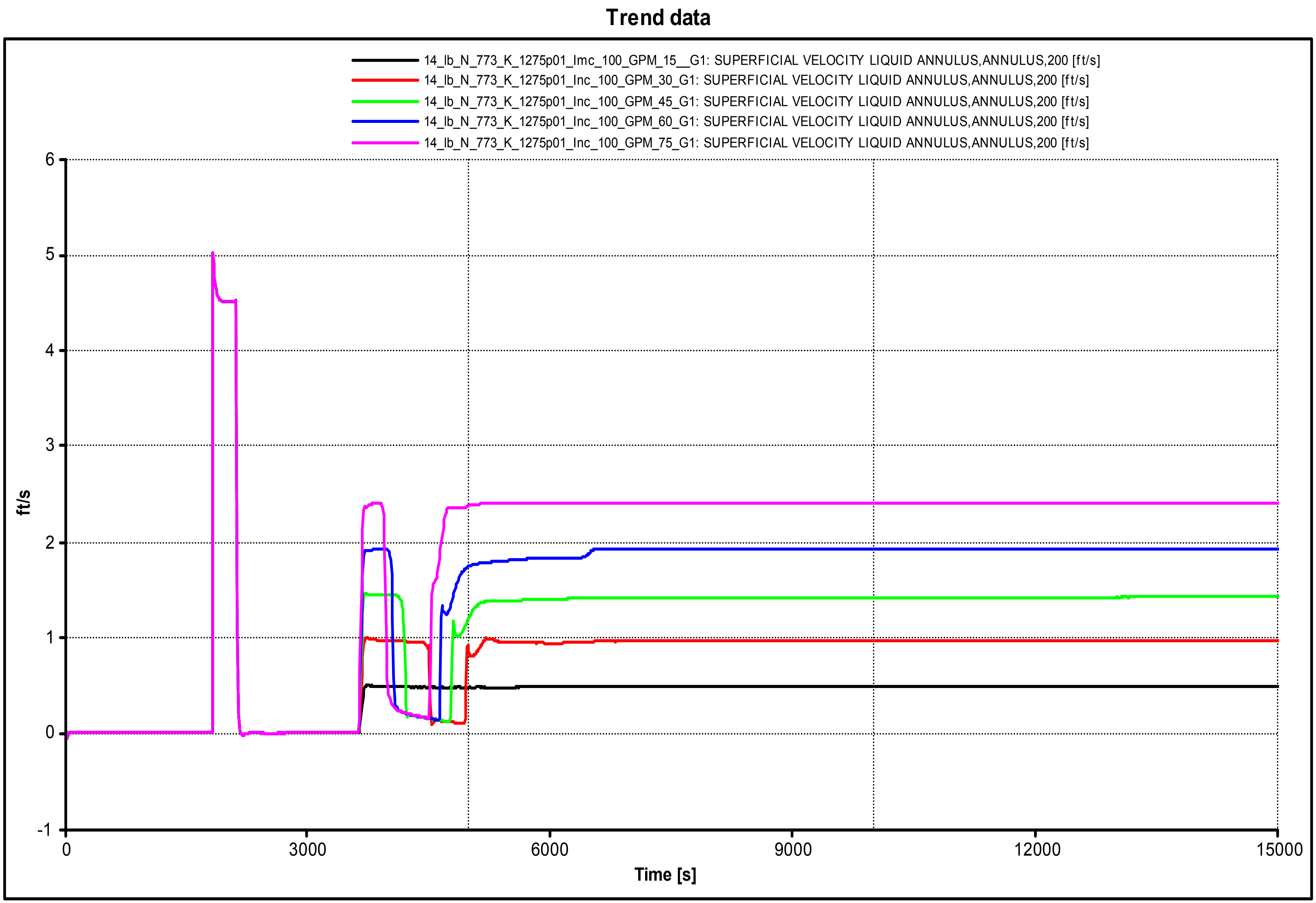

Fig. 68—Liquid superficial velocity at outlet of annulus, Geometry 1, inclination 10°, circulation rate 15, 30, 45, 60, & 75 GPM.

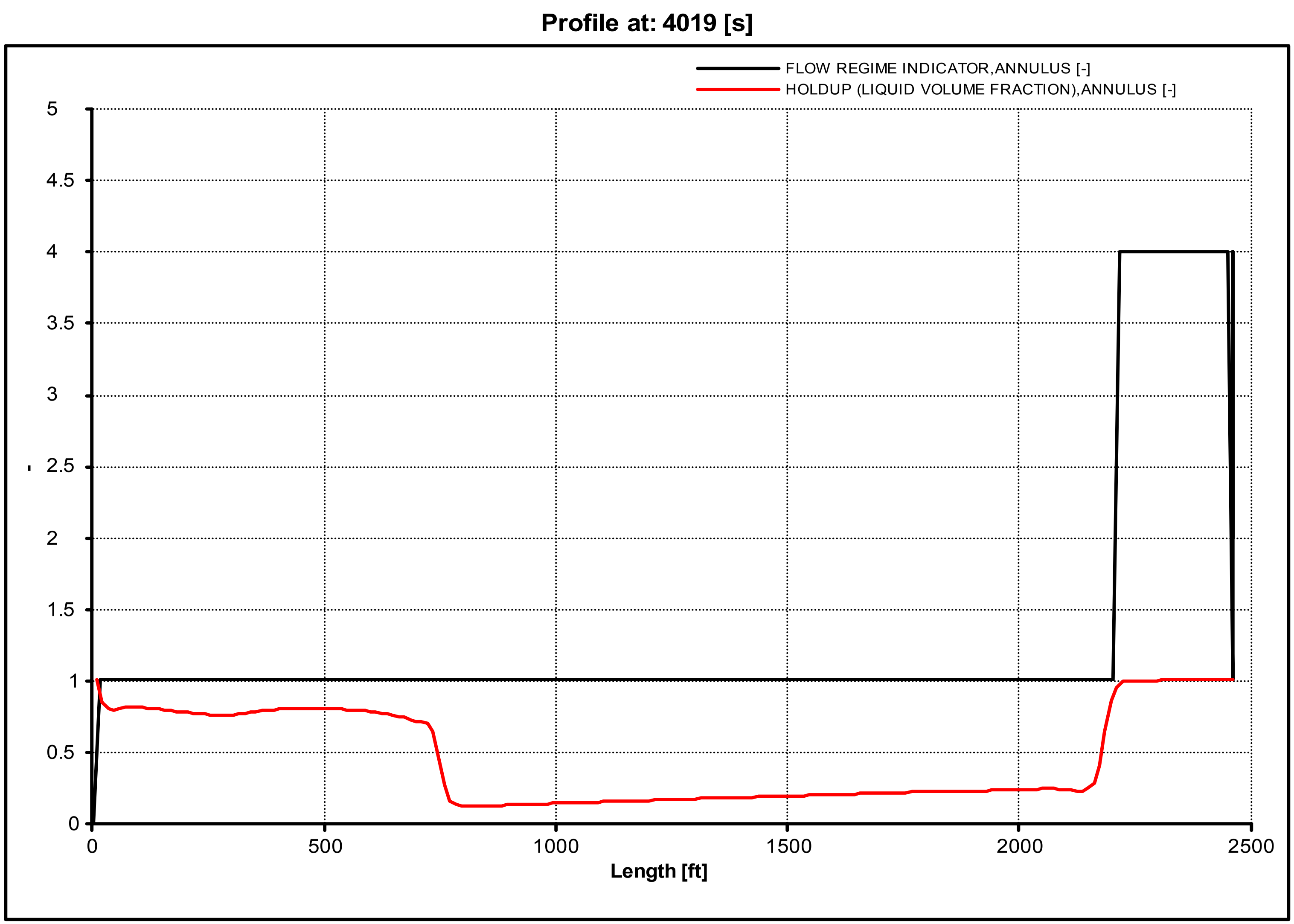

Fig. 69—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 10°, circulation rate 45 GPM

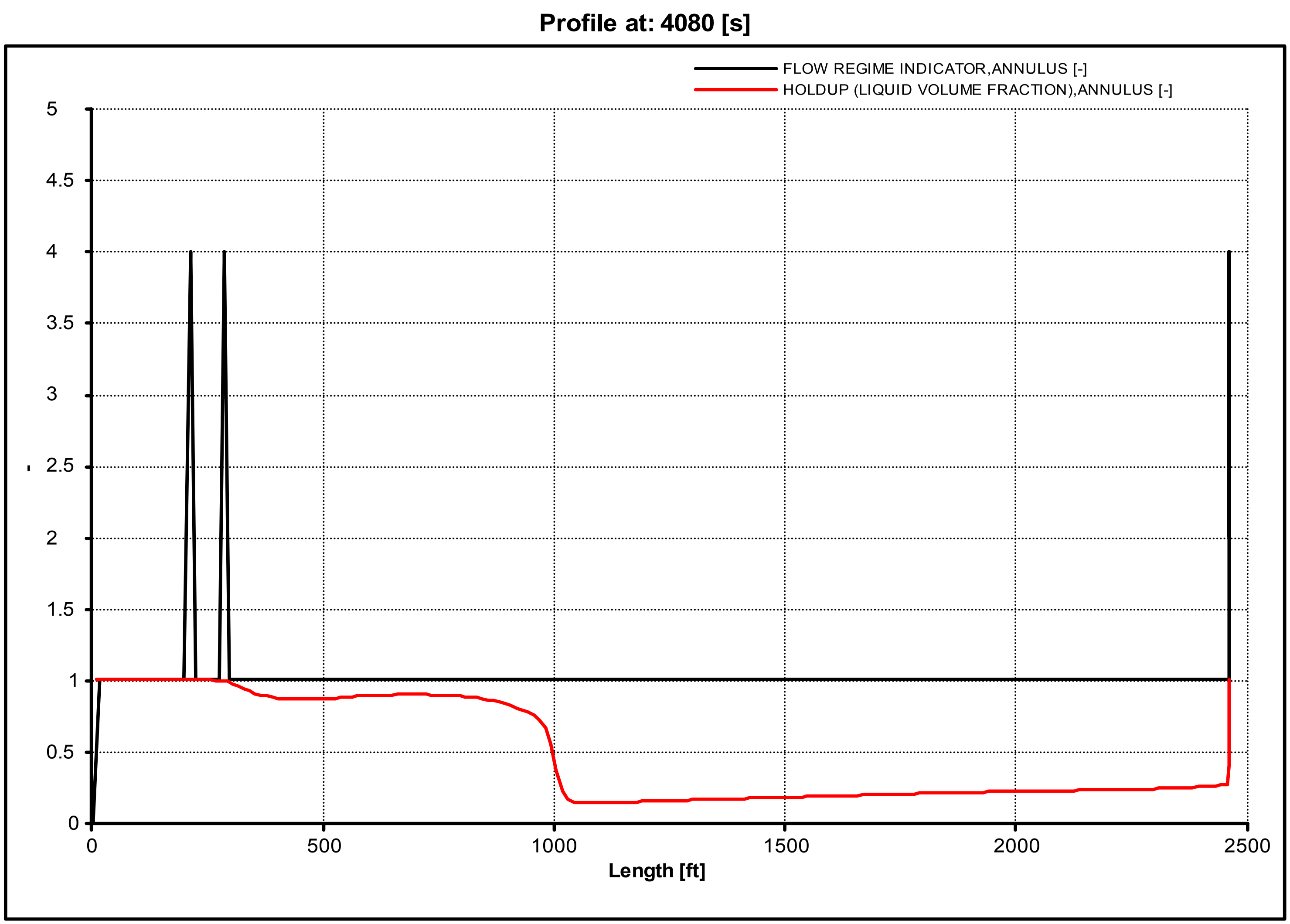

Fig. 70—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 1, inclination 10°, circulation rate 60 GPM.

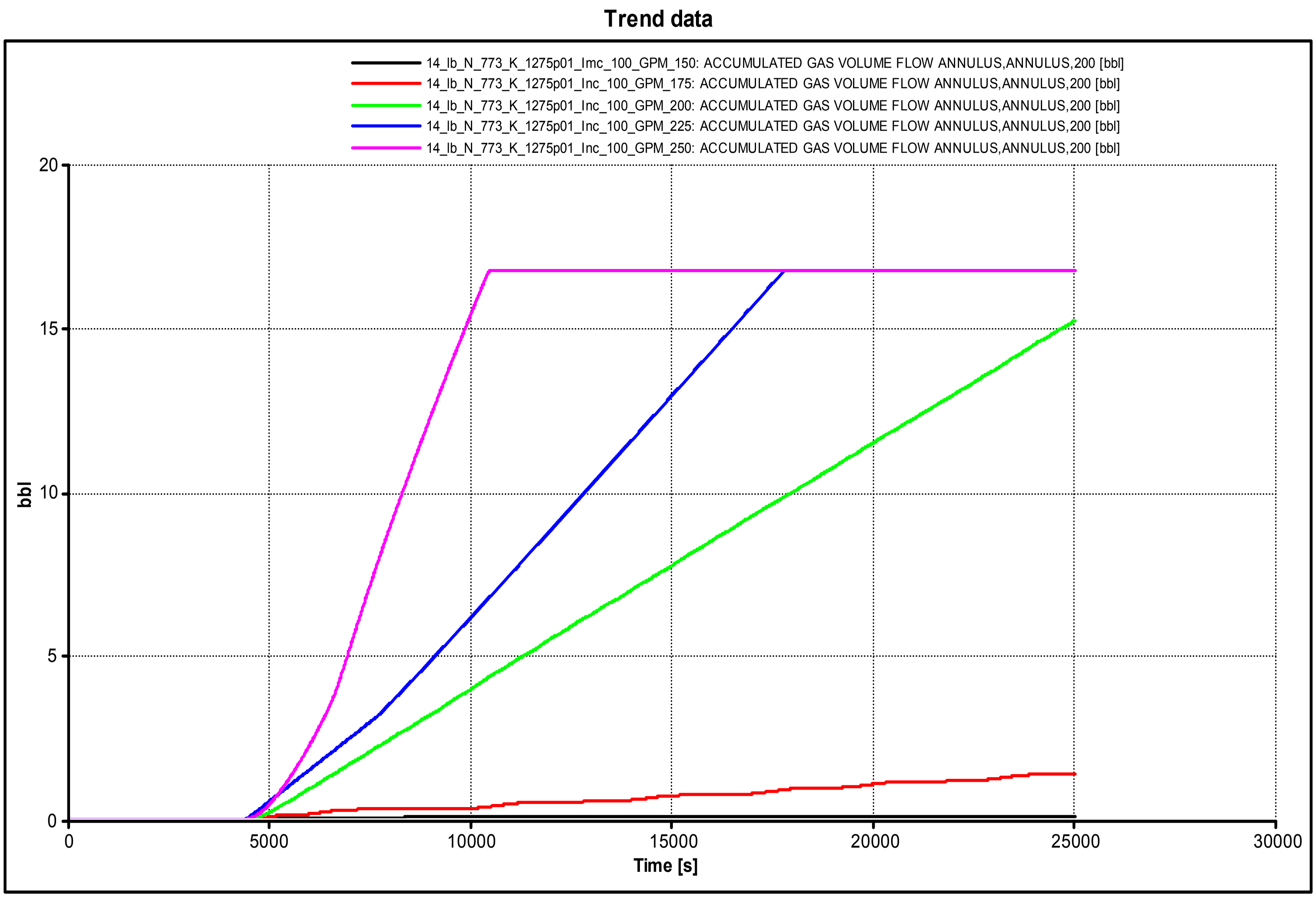

Fig. 71—Accumulated gas out at outlet of annulus, Geometry 2, inclination 10°, circulation rate 150, 175, 200, 225, & 250 GPM.

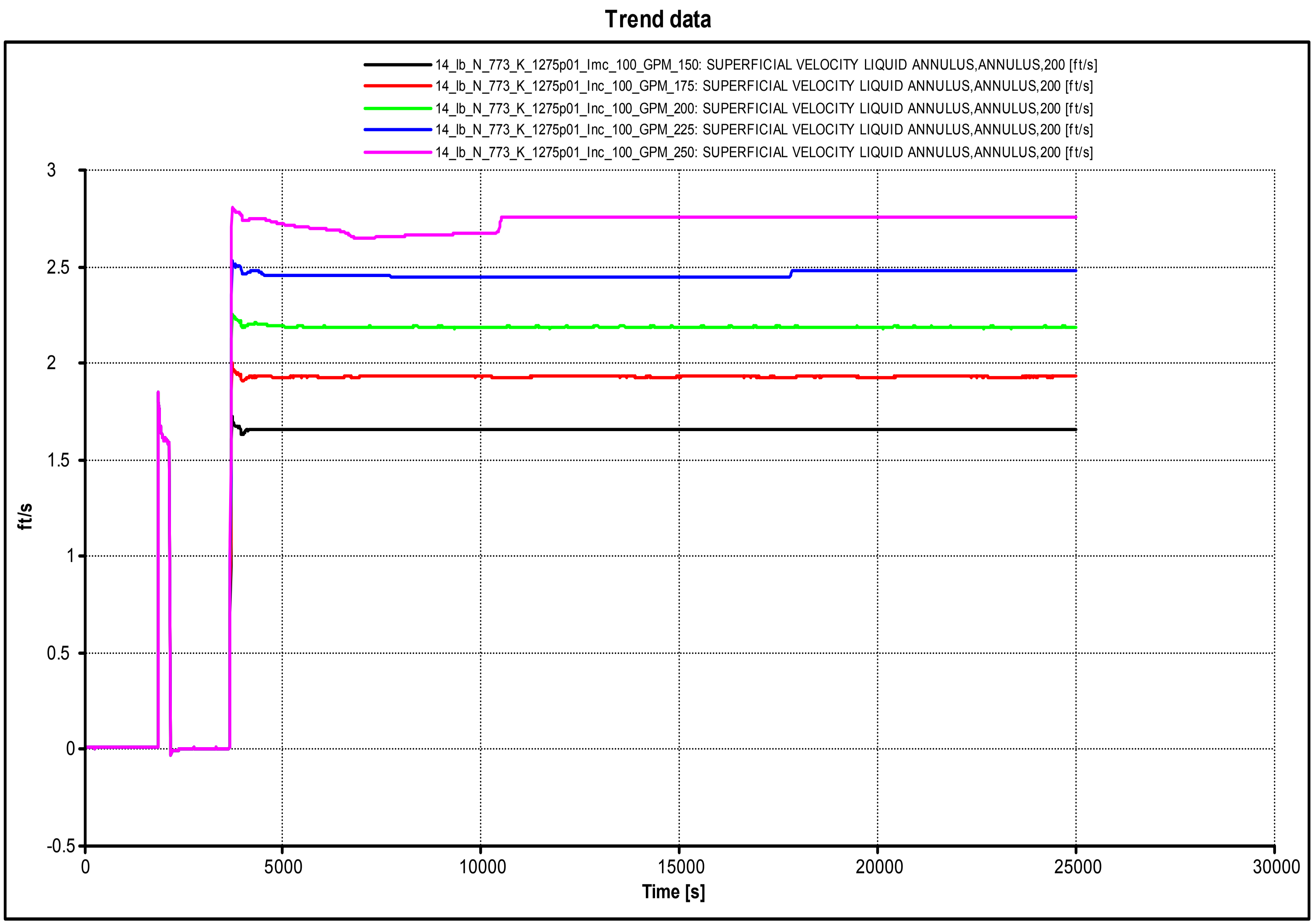

Fig. 72—Liquid superficial velocity at outlet of annulus, Geometry 2, inclination 10°, circulation rate 150, 175, 200, 225, & 250 GPM.

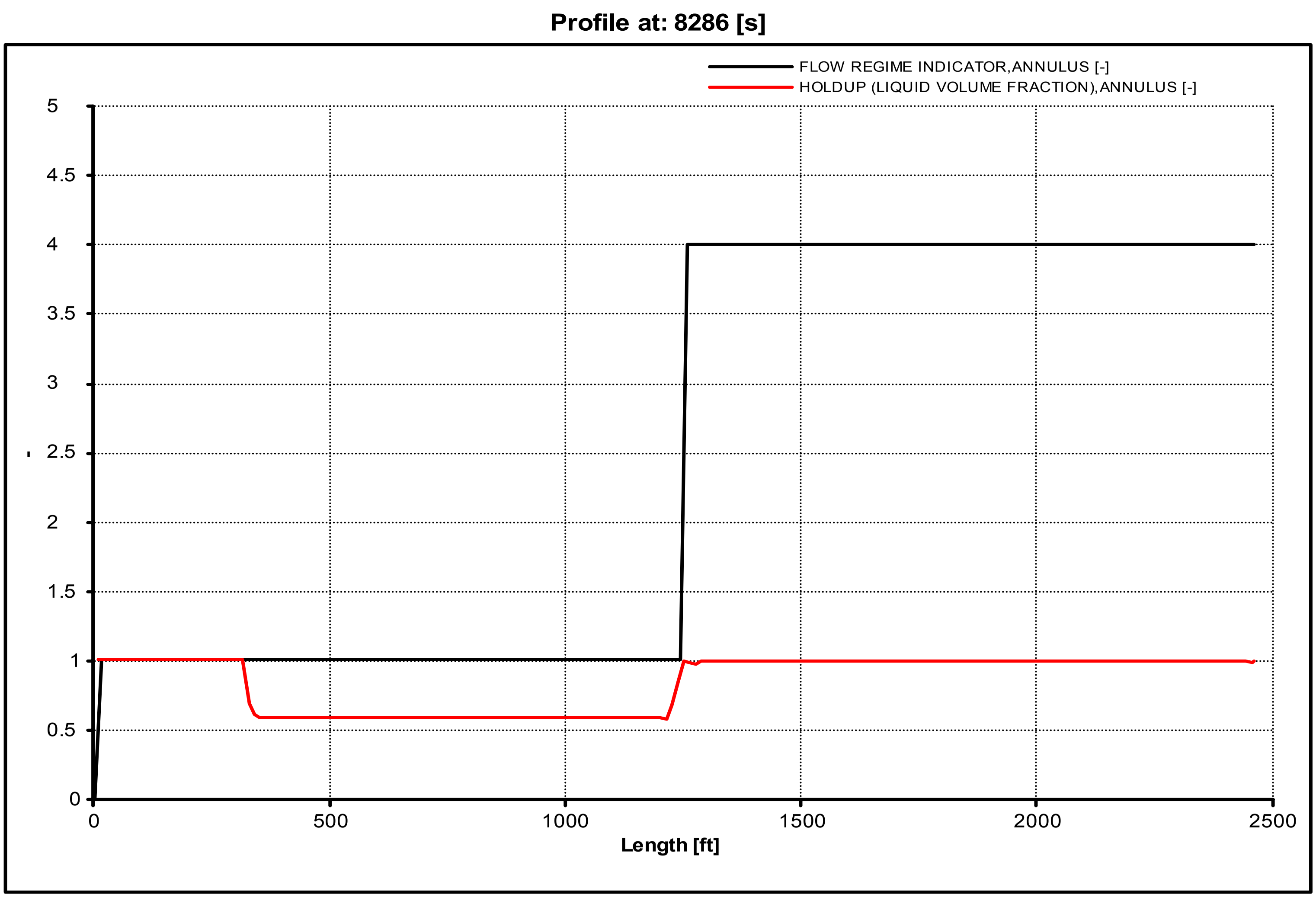

Fig. 73—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 10°, circulation rate 200 GPM.

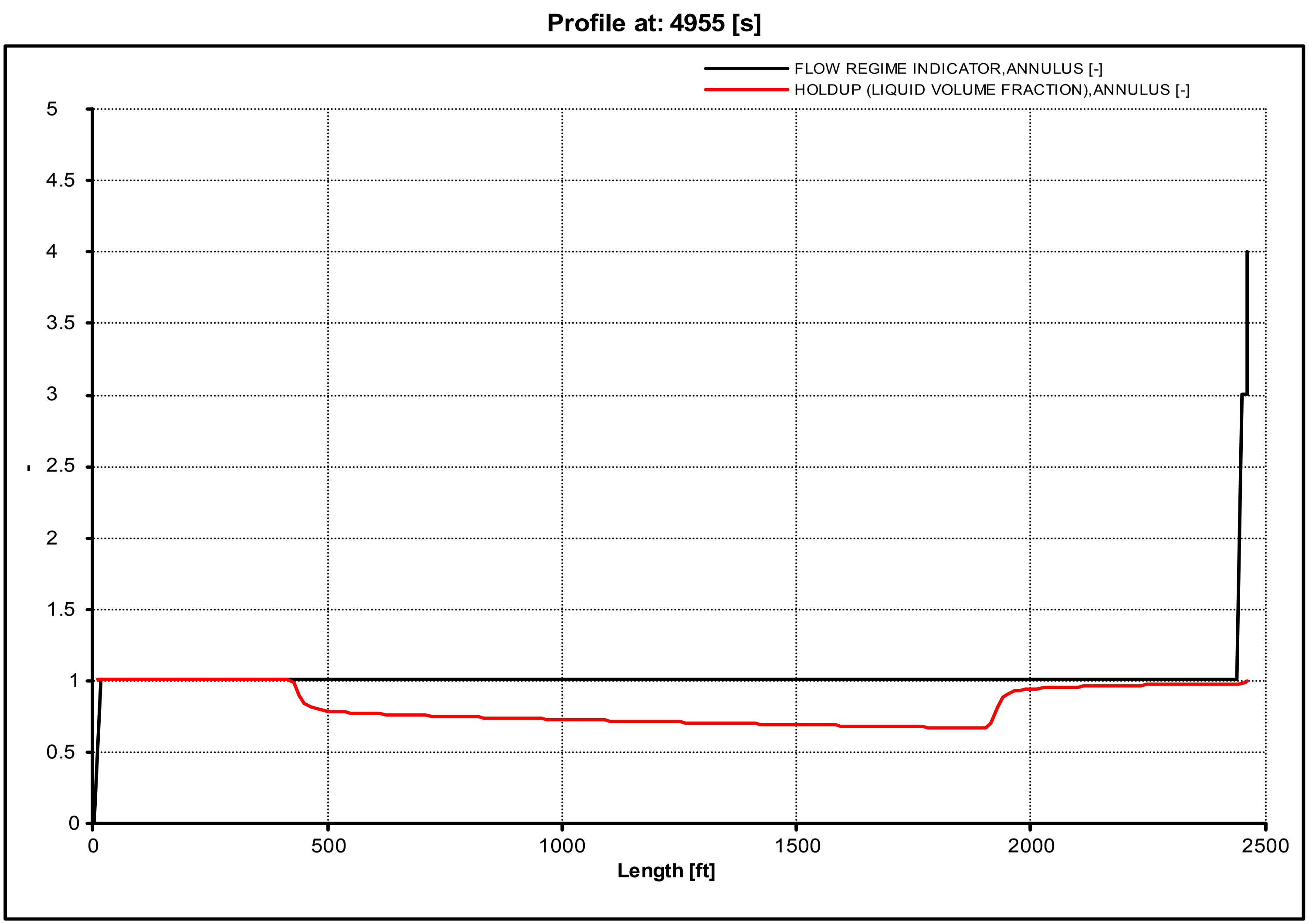

Fig. 74—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 2, inclination 10°, circulation rate 250 GPM.

Geometry 3

Figs. 75 to 78 represent the data for Geometry 3. Similarly to the two previous geometries, lower circulation rates and annular velocities were obtained using the 14-ppg viscous mud. For the run performed with water, a circulation rate of 600 GPM and annular velocity of 3.4 ft/sec were required to remove the kick. These values were lowered to a circulation rate of 500 GPM and an annular velocity of 2.75 ft/sec. From Figs. 77 and 78, several flow regimes are present. A region of bubble flow is present in advance of the majority of the gas kick. In gas-kick region the flow alternates between slug and stratified flow.

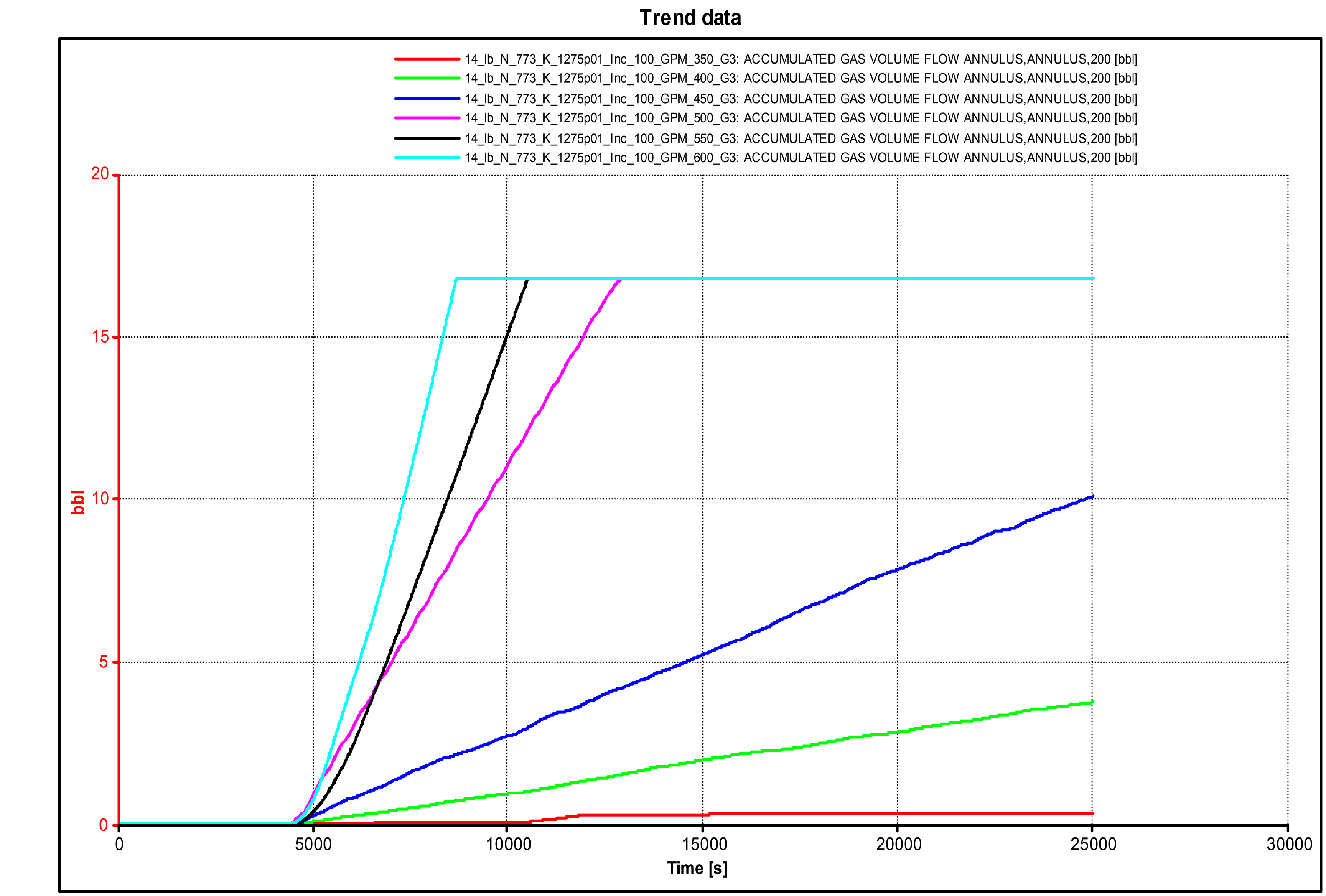

Fig. 75—Accumulated gas out at outlet of annulus, Geometry 3, inclination 10°, circulation rate 350, 400, 450, 500, & 600 GPM.

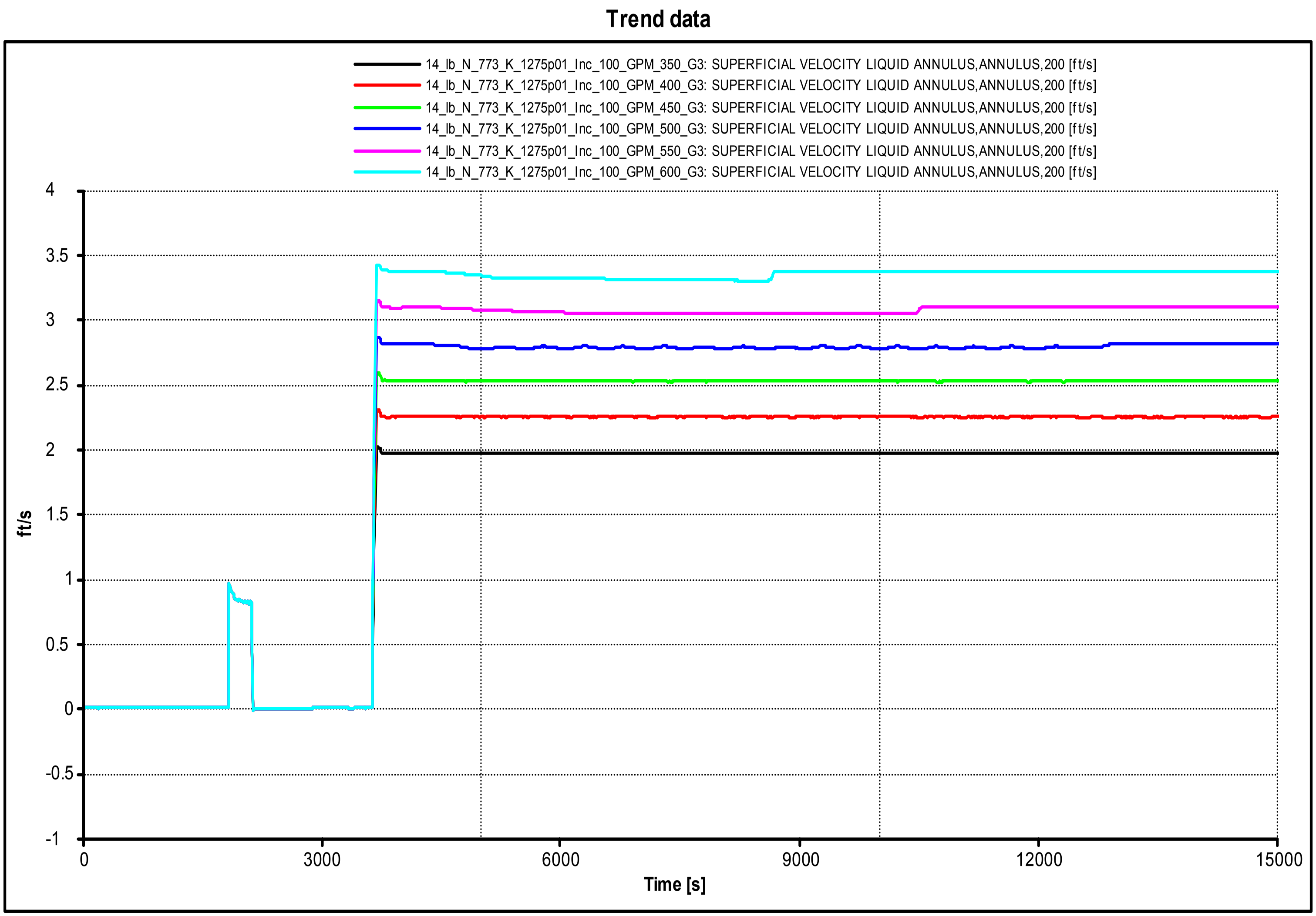

Fig. 76—Liquid superficial velocity at outlet of annulus, Geometry 3, inclination 10°, circulation rate 350, 400, 450, 500, & 600 GPM.

Profile at: 1.883e+004 [s]

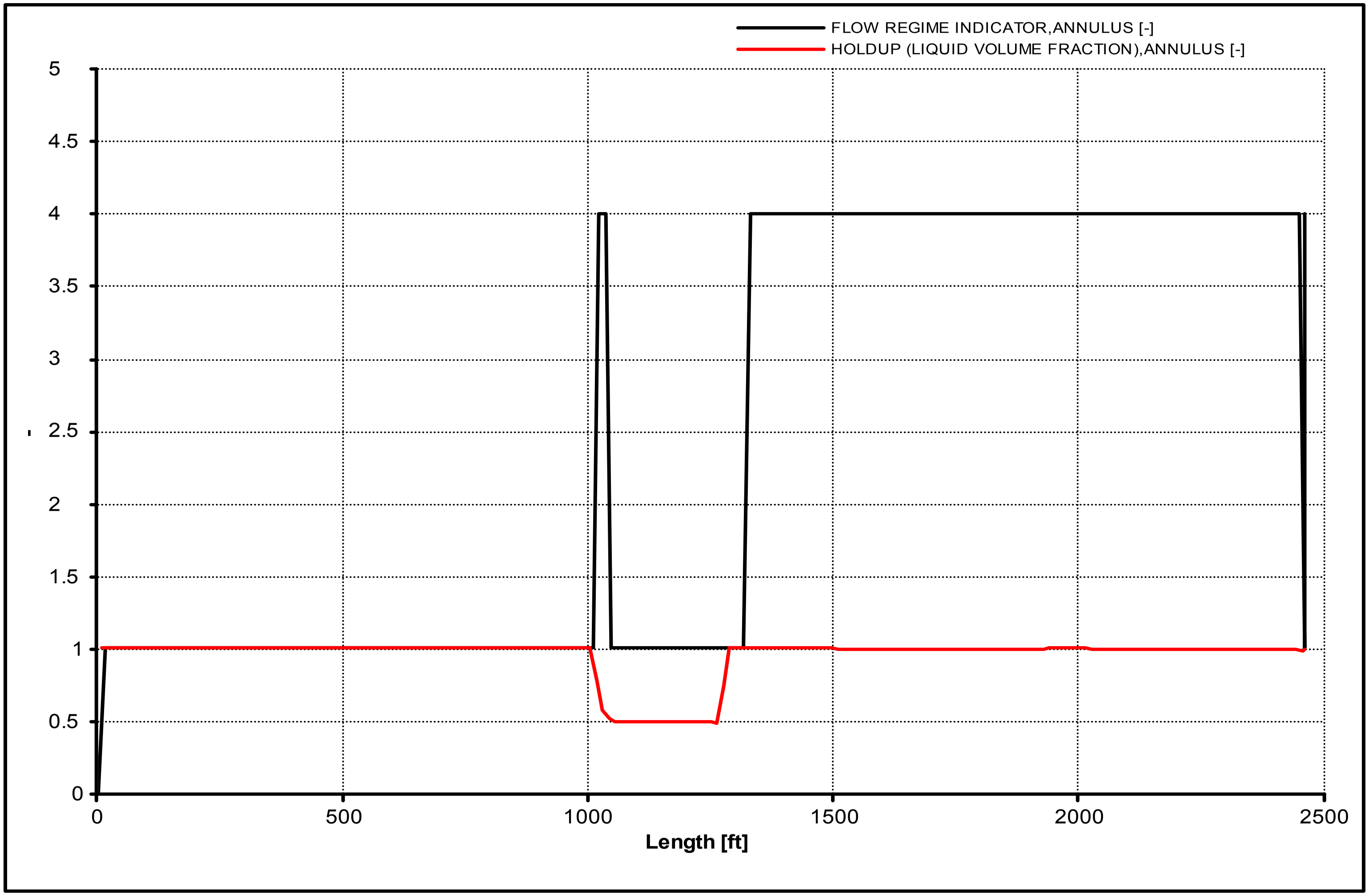

Fig. 77—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 10°, circulation rate 450 GPM.

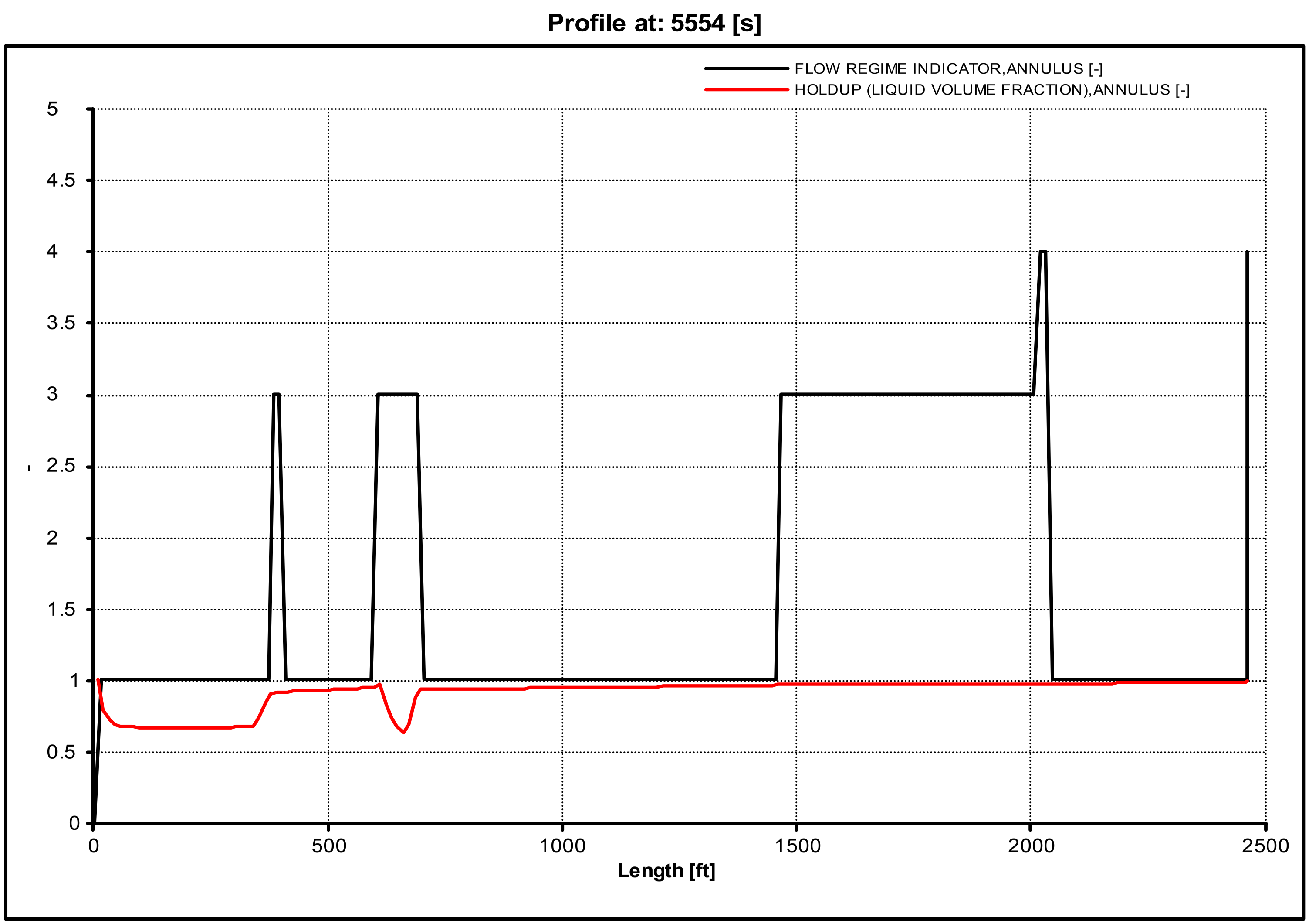

Fig. 78—Liquid holdup and flow regime indicator at outlet of annulus, Geometry 3, inclination 10°, circulation rate 550 GPM.

SUMMARY OF RESULTS

Effects of Horizontal Section Inclination

Cases in which the wellbore inclination is greater than horizontal needed an increased circulation time and circulation rate to efficiently transport the kick. The higher the inclination, the more difficult it becomes to remove the gas kick from the high side of the wellbore. In horizontal wells with inclinations of zero, the kick is easily removed from the wellbore at all circulation rates. For wells with inclinations lower than horizontal, the gas migrated out of the horizontal section before the circulation began. A nonuniform section located at the top of each trend of accumulated gas out reflects some of the gas influx migrating up the drillpipe. Once circulation begins, the gas is displaced from the drillpipe and circulated through the annulus. Table 5 lists kick removal times assuming piston-like displacement for a given circulation rate for each geometry; wellbores with higher inclinations take considerably more time to displace the kick influx. Circulation rate also affects kick removal. The higher the circulation rate, the closer the removal time is to the mode of piston-like displacement.

Effects of Annular Area and Annular Velocities

As hole size or annular area increases, displacing the gas kick from the wellbore for inclinations greater than horizontal becomes more difficult. **Fig. 79** illustrates needed annular velocities for efficient removal of the kick for the three given geometries. The figure shows that increasing annular area requires a higher annular velocity. In geometries of larger annular areas, it may be difficult or impossible to achieve circulation rates high enough to yield the desired kick-removal annular velocity.

Effects of Friction

The majority of runs, if not otherwise specified, were performed with a relative roughness value of 0.0018. **Fig. 80** illustrates the simulation study varying annular friction. As the relative roughness value increased, the kick-removal process became more efficient.

Effects of Mud Properties

Several simulations were run varying mud properties. Power-law coefficients *n* and *K* were inputted into the simulator, which computed the effective viscosities on the basis of circulation rates and annular geometries. The higher the effective viscosity, the more efficiently the influx was transported from the wellbore. A simulation varying the density and power-law coefficients of the circulating fluid showed that with increasing density, gas removal efficiency became more effective. However, the overriding parameter was effective viscosity. These results are shown in Figs. 62 to 68.

Observed Flow Regimes

For inclinations greater than horizontal, several flow regimes are present. Bubble flow is observed in front of the migrating gas kick. Slug flow or stratified flow is present in the portion of the wellbore where the majority of the gas is present. A stratified flow regime exists behind the gas influx. For horizontal cases, a stratified flow regime is present throughout the removal of the gas influx. For inclinations below horizontal, slug flow or stratified flow may be present in the portion of the wellbore the majority of the gas occupies. This is followed by a region of bubble flow until stratified flow is reached. These results are illustrated in Figs. 52 to 60, 69, 70, 73, 74, 77, and 78.

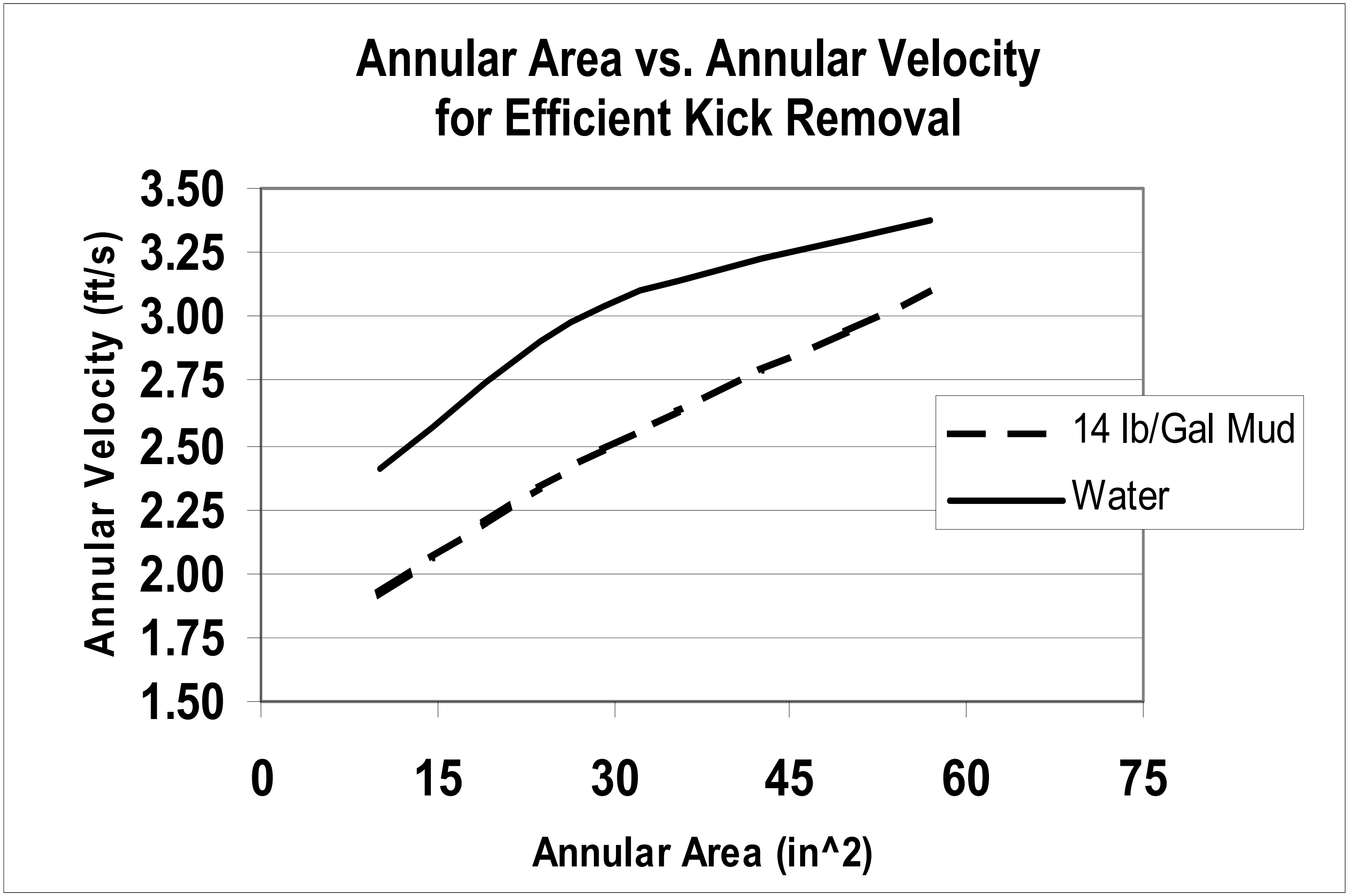

Fig. 79—Annular area vs. annular velocity for efficient kick removal.

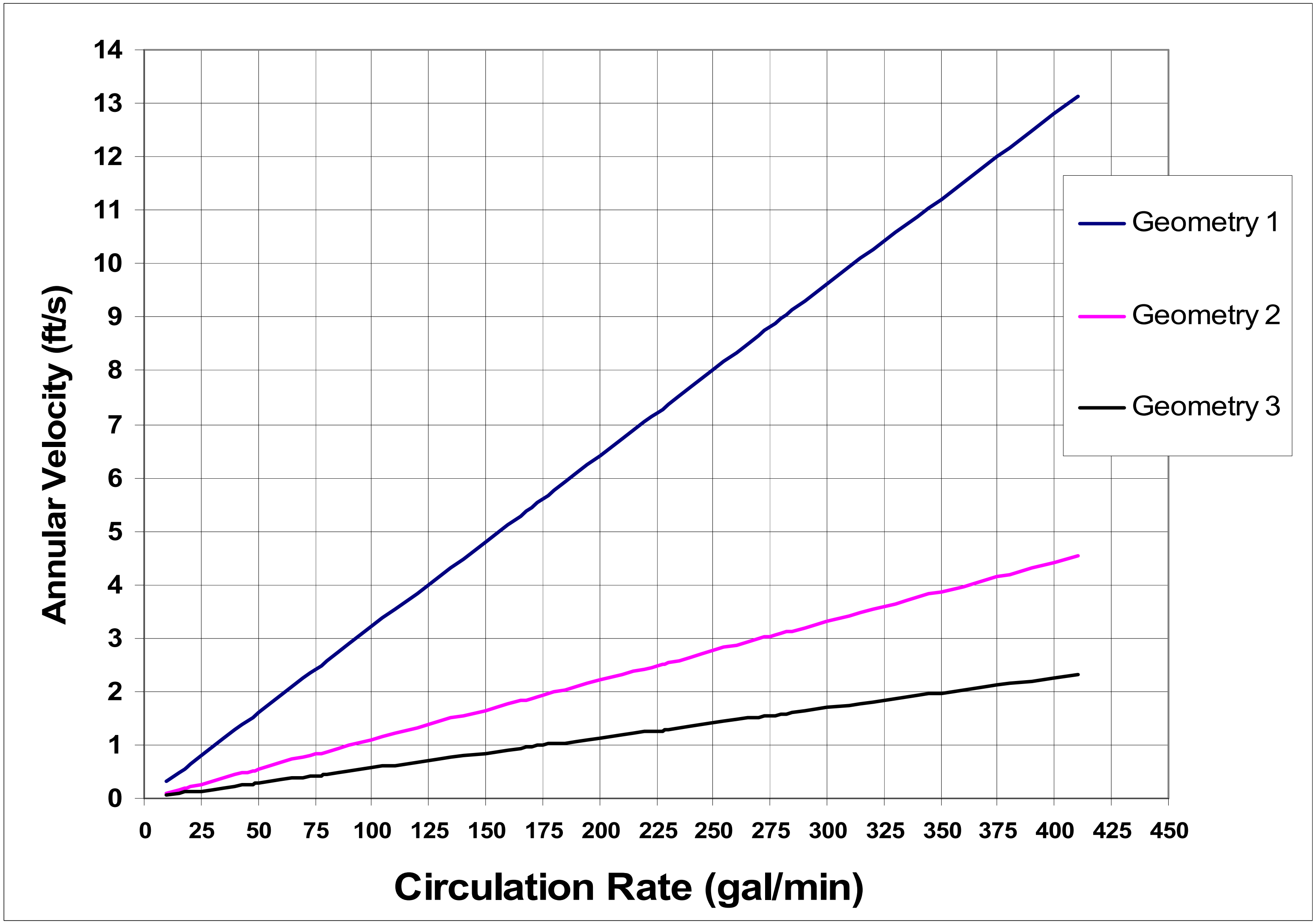

Fig. 80—Circulation rate vs. annular velocity for specific geometries.

CONCLUSIONS

The results from the simulation runs are summarized in the following list:

- Difficulty removing gas kicks may be encountered in wellbores with inclination greater than horizontal. The higher the inclination, the more pronounced this effect.

- As annular area increases, higher circulation rates are needed to obtain the needed annular velocity for efficient kick removal. For water as a circulating fluid, an annular velocity of 3.4 ft/sec is recommended.

- Lower kick-removal annular velocities may be obtained by altering mud properties. Fluid density slightly increases kick removal, but higher effective viscosity is the overriding parameter.

- Increasing relative roughness slightly increases kick-removal efficiency.

- Bubble, slug, and stratified flow are all found to be present in the kick-removal process. Slug and bubble flow are the most efficient at transporting the gas kick.

RECOMMENDATIONS

Recommendations to Industry

From this study several recommendations to industry can be made. The negative effect of horizontal sections at inclinations greater than horizontal can clearly be seen. These trajectories are often unavoidable in mountainous or uneven terrain, lease boundaries, and location of producing formation. However, these inclinations should be avoided wherever possible. Hole size and completion methods should also be considered when planning an inclined horizontal section. Larger annular areas require higher circulation rates to obtain the needed annular velocity to displace the gas kick. If the annular area is too large, the needed circulation rate may be unobtainable because of pump limitations. In this situation, fluids with greater effective viscosities may be used to remove the kick at lower circulation rates.

In general removing a gas kick from an inclined horizontal well is considerably more difficult than in vertical and deviated wells. This is a result of the buoyancy forces opposing the direction of circulation. To overcome this effect, circulation should occur at a sufficiently high value to reach the required annular velocity to efficiently displace the kick. Once the kick influx reaches the vertical section and the choke pressure begins to rise, the circulation rate may be decreased. This procedure is expounded upon in the work of Gjorv,[11] which discusses well-control procedures and the effects of kick size, intensity, and kill rate.

Recommendations for Further Research

Further research could be conducted in several areas. A wider range of inclination values could be modeled. Studies investigating the effects of fluid properties could also be performed. This would include pumping slugs of viscous and oil-based fluids, and considering the effects of gas kicks going into solution. OLGA also lends itself to being used for a complete well-kill simulator along with an under balanced drilling simulator.

NOMENCLATURE

k	=	power law consistency index
n	=	power law exponent
γ_g	=	specific gravity

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